PETROLEUM MONITORING AGENCY

CANADA

CANADIAN PETROLEUM INDUSTRY

1981 MONITORING SURVEY

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FOREWORD

This survey on the activities and financial performance of the oil and gas industry covers the year 1981. It is based on data from 101 reporting companies for which there were comparable data in 1980.

The year 1981 witnessed major changes in Canadian energy policy as well as in international energy and economic areas. First, many of the measures announced in the National Energy Program (NEP) in October 1980 took effect on January 1, 1981. Also, in the second half of 1981, the federal government signed five year energy pricing and taxation agreements with each of the major producing provinces--Alberta, British Columbia, and Saskatchewan. These agreements modified some of the provisions of the NEP--in particular, the agreements provided for increases in the schedule of prices for oil and gas. Finally, under the combined pressure of decreasing global demand for oil and increasing supply from non-OPEC sources, international oil prices began to soften in 1981, particularly in the latter part of the year.

This survey does not reflect the positive impact on the industry of the revenue and tax changes announced by Alberta and by the federal government in April and May of 1982 respectively and the royalty reductions introduced by Saskatchewan in July of 1982. The results of these changes will be included in future Monitoring Surveys.

An important component of the NEP is the provision for government funded Petroleum Incentives Program (PIP) grants to support exploration and development activities. The federal government (on a provisional basis pending the passing of enabling legislation) and the Alberta government each began receiving applications for PIP grants on April 19, 1982. These grants, which can be applied against qualified expenditures retroactive to January 1, 1981, were accrued within the financial records of the industry in 1981. Companies are able to use these grants, for cash management purposes, to offset their liabilities for the Petroleum and Gas Revenue Tax (PGRT). The PGRT, which came into effect on January 1, 1981, is a new federal tax on oil and gas production revenues and royalty income.

As noted in the Monitoring Survey for the first six months of 1981, companies which were eligible for PIP grants would be able to use these grants to offset their liabilities for the PGRT. The manner in which the offset would be treated would have an impact on net income and cash flow.

In February of 1982, the Canadian Institute of Chartered Accountants (CICA) recommended that, for the purposes of financial reporting, PIP grants be taken into income in the same manner as the exploration and development expenditures that they support. Further, the Institute recommended that the PGRT be charged to income at the same time as the related revenues are taken into income.

All of the PMA reporting companies followed the CICA guideline in the submission of their completed questionnaires and this survey reflects that result. However, at the time of writing, there is still some debate on the issue.

A number of takeovers and acquisitions took place in the petroleum industry in Canada during the course of 1981. As a result, some PMA reporting companies have been transferred to different company groups. It was decided not to establish a new 'Canadian integrated' group because, in view of the small number of companies involved, there would have been a serious risk of disclosure of individual company data. In order to provide for comparable year-over-year results, data for 1980 have been adjusted to reflect the changes in 1981. Therefore, company group data for the year 1980 presented in this survey do not equate to those presented in the 1980 survey.

The Energy Monitoring Act contained in Bill C-106 provides for an expanded monitoring mandate and the continuation of the PMA. Among other provisions, this Act raises the minimum reporting threshold from $5 million in assets to $10 million and provides for the communication of certain data to some Government departments. These latter provisions are designed to minimize the reporting burden on industry.

The basic task of the PMA is to present complete and factual data on the activities and financial performance of the oil and gas industry. The intent is to present an objective and educational reference document in a format consistent with information generally available from other sources. Policy makers and analysts may use the factual base provided by the survey to form their own subjective evaluations and judgements.

My retirement as Chairman of the Petroleum Monitoring Agency will take effect shortly after this 1981 Monitoring Survey has been released. It has been a privilege for me to serve the Canadian people and I wish to thank my Minister, the Honourable Marc Lalonde, my staff, and the oil and gas industry for their support and understanding. My assigned task of establishing the PMA and gaining recognition and acceptance for its monitoring mandate has been achieved. I am confident that the Canadian people will continue to be well served by the Agency and its new Chairman.

Harold A. Renouf
Chairman

Ottawa
July 13, 1982

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EXECUTIVE SUMMARY

The constant dollar value of the goods and services (GNP) produced in Canada rose by 3% in 1981. However, this increase was concentrated in the first half of the year, as economic growth declined in the second half of 1981.

Canadian consumption of petroleum products and natural gas declined by 6 and 5% respectively. These consumption declines reflect a number of factors including slow economic growth, higher prices, and the effect of various conservation and off-oil initiatives.

Canadian production of petroleum and natural gas decreased by 8 and 3% respectively compared to 1980 levels. Two main factors contributed to the decreased petroleum production--declining productivity of mature producing fields in western Canada and temporary production cutbacks implemented by the Government of Alberta.

Financial Results--Petroleum Industry

Higher wellhead crude oil prices and higher prices for natural gas in 1981 offset the impact of lower production levels so that industry upstream revenues advanced by 3% in that year. Revenues from total operations rose by 21% to reach more than $51 billion.

Total deductions against revenues rose by 31%, or more rapidly than the growth in revenues. As a result, the net income (after-tax profits) on overall operations of the industry declined by $1.6 billion, or by 34%, to about $3 billion.

Nearly $1.3 billion of this reduction in industry net income was due to the 44% decline in profits from operations in the upstream sector. The most important factors contributing to the decline in upstream profits were higher operating costs, increased interest charges, and the Petroleum and Gas Revenue Tax (PGRT).

The Canadian Institute of Chartered Accountants (CICA) has recommended that, for the purposes of financial reporting, Petroleum Incentives Program (PIP) grants be taken into income in the same manner as the exploration and development expenditures that they support and that the PGRT be charged to income at the same time as the related revenues are taken into income. All of the PMA reporting companies followed the CICA guideline in the submission of their completed questionnaires.

Net income from downstream operations declined by 6% to $1.4 billion, with 58% of the year's net income being recorded in the first half of 1981. After-tax profits on downstream operations in the second half of the year were 29% lower than those in the corresponding period of 1980. The weak performance in the second half of 1981 was caused by declining demand for petroleum products and increased competitive pressures as companies attempted to maintain their market shares.

Changes in the Petroleum Compensation Charge (PCC) had an important impact on downstream net income in 1981. Excluding inventory profits due to changes in the PCC, downstream net income in 1981 would have declined by 18% as compared to the actual decrease of 6%.

Net income on other Canadian operations dropped by 94% to $11 million. The major reason for this large decrease relates to the allocation of substantial amounts of interest expensed to this sector of operations by several reporting companies. This sector accounted for about 6% of total industry revenues in 1981, but 37% of total interest expenses charged to operations. This disproportionately large allocation of interest exaggerates the profit decline in this sector and understates reductions in the other three sectors of operations.

Net income on foreign operations declined by 36% to $113 million. Changes in accounting practices and the suspension of some U.S. metal mining operations contributed to this result.

The profit performance of the petroleum industry in 1981 was in marked contrast to the steady growth of the 1970s. In 1972, the petroleum industry earned $18 in net income for every $100 earned by the aggregate of all other non-financial industries (excluding petroleum). The comparable figures for 1979 and 1980 were $37 and $43. In 1981, the petroleum industry earned $34 for every $100 earned by other non-financial industries--somewhat less than the equivalent ratio for 1979.

The rate of return on shareholders' equity rose from 10% in 1972, which mirrored the average for all other non-financial industries at that time, to over 21% in 1980--well above the 15% average for other non-financial industries in that year. Although the rate of return for the petroleum industry declined in 1981 to about 12%, it was still above the average of 11% for other non-financial industries. Similar results are obtained using capital employed as the base of measurement.

Cash Flow and Other Sources of Funds

Total funds available to the industry in 1981 were $22.4 billion, an increase of 46% over the previous year. Cash flow from operations declined by 15% to $8.1 billion, but a dramatic rise of 146% in external sources (primarily from new long-term debt) resulted in the overall increase in available funds. External sources of funds accounted for $14.3 billion, or 64%, of the industry's total cash flow in 1981, compared to 38% in 1980.

The report contains an analysis of the relative ability of the industry, and the various groups of companies therein, to cover their total interest charges from internally generated funds. The analysis indicates that interest charges for Canadian controlled companies accounted for about 38% of their 1981 internal cash flow. In marked contrast, the comparable figure for foreign controlled firms was 7%.

An important new source of funds for the industry in 1981 was government Petroleum Incentives Program (PIP) grants. PMA reporting companies estimated their entitlement to PIP grants to total $670 million in 1981, of which $470 million will be funded by the federal government and $200 million by the Government of Alberta. Of the $670 million total, $563 million, or 84%, of the PIP grants accrued to Canadian controlled companies.

On an overall basis, governments' contribution to industry cash sources of $670 million of PIP grants was offset by $924 million in PGRT for a net deficit of $254 million. The $254 million was distributed between a $234 million surplus of PIP over PGRT for Canadian controlled companies and a $488 million deficit for foreign controlled firms.

Capital Expenditures

Capital expenditures by the petroleum industry increased by 21% to reach $11.6 billion. Within this total, expenditures in Canada amounted to $9.8 billion, up 17% over the 1980 level. Upstream capital expenditures decreased 3% to $6.7 billion, primarily as the result of reduced exploratory activity on provincial lands, although exploration expenditures on Canada Lands increased by 67%. Downstream capital expenditures increased by $1.2 billion to reach $2.0 billion as companies modified refineries in the light of changing demand patterns for refined products.

Cash Flow and Financing of Investment

Internal cash flow in the upstream sector declined by 23% in 1981. Upstream capital expenditures as a percentage of upstream internal cash flow increased from 103 to 130%. On average, upstream capital expenditures of Canadian controlled companies were equal to 169% of their upstream internal cash flow. The comparable figure for foreign controlled firms was 107%.

Data indicate that the petroleum industry in 1981 had a considerably lower proportion of its internal cash flow from total operations (after major expenditures requiring cash outlays but excluding capital expenditures) available for capital expenditures and other uses than it did in 1980. In 1980 and 1981, Canadian controlled companies had 48 and 27% respectively of their total internal cash flow available for capital expenditures and other uses. Comparable ratios for foreign controlled companies were 67 and 49%.

Dividends

Dividend payments to shareholders increased by 19% to $1.1 billion. Dividends paid as a percentage of net income were approximately the same for Canadian controlled companies as for foreign controlled companies, at 35 and 36% respectively. These figures contrast with the ratio of 20% for each group in 1980. The higher pay-out ratio in 1981 results from the net income of each group of companies dropping by over 30%, while dividend payments increased (24% by Canadian controlled companies and 17% by foreign controlled companies).

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Other Uses of Funds

All other uses of funds, consisting mainly of funds used for acquisitions, increased by over 300%, from $1.6 billion to $6.6 billion. Nearly all of this $5 billion increase was by Canadian controlled companies, whose outlays in this category reached $6.3 billion, 80% of which was for petroleum-related acquisitions of foreign controlled companies.

Estimates of Revenue Shares

Estimates of revenue shares are calculated on the basis of the methodology used by the federal government and the governments of the producing provinces in the Energy Pricing and Taxation Agreements (EPTA) signed in the fall of 1981. On this basis, the estimated revenue shares in 1981 are: industry 50.4%, provincial 30.4%, and federal 19.2%. Decreases of 4.5 and 4.0 percentage points in the provincial and industry share respectively from 1980 to 1981 were offset by an 8.5 percentage point increase in the federal share.

The framework of the EPTA documents considered operating costs to be a part of industry's share of total revenues. This represents a considerable change from the methodology used in the 1980 Monitoring Survey where such costs were excluded from the industry share. Excluding operating costs, the estimated revenue shares in 1981 are: industry 39.5%, provincial 37.1%, and federal 23.4%. These estimates compare very closely to those in the federal government's NEP Update of May 1982, where operating costs were excluded from the calculation of the industry share.

Research and Development

A total of 40 PMA companies, mostly larger companies, reported energy R&D expenditures in 1981, as compared to 37 companies in 1980. Expenditures undertaken by companies using their own equipment and laboratories totalled $332 million in 1981, an increase of 64%. In addition, R&D expenditures carried out under contract for the reporting companies almost doubled to $117 million. R&D expenditures related to in-situ production techniques ($122 million) and oil and gas exploration and production ($118 million) were the two most significant components of outlays undertaken directly by reporting companies.

Ownership and Control

The estimated level of foreign ownership of the oil and gas industry in Canada, using petroleum-related revenues as the measurement base, declined by 6.7 percentage points to 67.2% in 1981. Foreign control declined by 6.5 percentage points to 74.8%. The declines in foreign ownership and control in 1981 were dramatic compared to those over the decade 1971-80.

Takeover activity in the Canadian oil and gas industry was the most important single factor accounting for the decreases in foreign ownership and control in 1981. Of the 6.7 and 6.5 percentage point decreases in foreign ownership and control, takeover activity accounted for 4.1 and 5.7 percentage points respectively. Purchases by Canadians of shares previously held by non-residents in both Canadian controlled and foreign controlled companies resulted in an estimated decline of 1.4 percentage points in the level of foreign ownership in 1981, but no change in control.

The 1981 decreases were such that the relative geographic distribution of foreign ownership and control between the United States and other countries did not change markedly. About 61% of the drop in foreign ownership was accounted for by increased Canadian public sector ownership, including federal and provincial crown corporations as well as public sector interest in private sector companies.

International Flows of Funds

The petroleum industry accounted for a net outflow of funds from Canada of $5.1 billion in 1981. The major change in the international flows of funds was an outflow in the capital account of foreign controlled companies of more than $4.8 billion. This latter outflow represented a reduction in the level of foreign direct investment in Canada as a result of takeover activity in 1981.

The capital account outflows for the petroleum sector show only a portion of the total international flows of funds for the overall economy. In order to obtain a complete picture of the international flows of funds resulting from takeovers, offsetting inflows to other sectors of the economy would also have to be considered. Since some of the acquiring companies involved in takeover activity were non-petroleum corporations, any offsetting inflows would not be reflected in the petroleum sector but in the sector in which the acquiring company was classified.

The total current account outflows in 1981 for PMA reporting companies were $810 million, up 30% from 1980. Dividend payments comprised $528 million, business service payments $201 million, and interest payments $81 million of these current account outflows.

I. OVERVIEW OF OPERATIONS

This chapter provides an overview of the operations of the petroleum industry in Canada during 1981. An introductory section provides a review of economic developments and of trends in the supply and demand for oil and natural gas. This is followed by a summary of the industry's[1] financial performance on total operations. The final section of this chapter examines the net income (after-tax profits) of the four major sectors of industry operations--upstream[2], downstream, other Canadian operations and foreign activities.

Introduction

The National Energy Program (NEP), which was tabled in Parliament on October 28, 1980, contained a number of measures that affected the operations of the oil and gas industry. Several important aspects of the NEP, notably the pricing schedules for crude oil and natural gas produced in Canada and the sharing of upstream revenues, were modified by energy pricing and taxation agreements between the federal government and the major producing provinces in the second half of 1981. Those elements of the NEP and of the subsequent federal-provincial agreements that directly influenced the operations of the oil and gas industry in 1981 are discussed in relevant sections of this report.[3]

The constant dollar value of all expenditures in the Canadian economy (Gross National Expenditure or GNE[4]) in 1981 was 3% higher than in 1980. This increase was concentrated in the first half of 1981, as economic growth declined in the last half of that year. As noted below, in spite of the higher level of economic activity, Canadian consumption of oil and natural gas declined in 1981.

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(1) PMA reporting companies accounted for approximately 87% of both estimated petroleum industry upstream production revenues and total upstream capital expenditures (see Appendix II). Although no definitive data are available, it is estimated that PMA companies account for more than 95% of petroleum industry revenues on total operations. Therefore, the reporting companies are referred to as 'the industry' in this report.

(2) A glossary of technical terms is included as Appendix I to this report.

(3) The glossary includes definitions of many of the measures introduced by the NEP and the federal-provincial energy agreements of 1981.

(4) Gross National Expenditure (GNE) measures the output of the economy by totalling all expenditures (consumption, government, etc.). GNE is equal to (apart from a residual error of measurement) Gross National Product (GNP), which measures the output of the economy by totalling all income streams (wages and salaries, interest, etc.).

Table 1.1 presents summary data on crude oil and natural gas supply and demand for 1980 and 1981. As shown, domestic petroleum production decreased by 8%(1) to 257 000 cubic metres per day (m^3/d) (1.6 million barrels per day (b/d)) in 1981. Conventional petroleum output averaged 201 000 m^3/d (1.3 million b/d), a decline of 8%. About 5% of this drop was due to declining productivity of mature producing fields in western Canada and 3% was due to production cutbacks invoked by the Alberta government. Synthetic crude oil production, which averaged 20 000 m^3/d (127 000 b/d) in 1981, dropped by 13% due to technical problems at producing plants. The level of production of natural gas liquids (propane, butane and ethane) remained approximately the same as in 1980 at 36 000 m^3/d (225 000 b/d).

The level of consumption of petroleum products in Canada decreased by 6% in 1981. This decline was due to a combination of weak demand resulting from slow economic growth, higher petroleum product prices, and the effects of various conservation and off-oil initiatives.

Natural gas production declined by 3% compared to 1980 reflecting a drop in both domestic consumption and exports. The decrease in domestic consumption resulted from a drop in demand for industrial and heating purposes, the latter reflecting generally mild climatic conditions across Canada in early 1981.

Net exports of natural gas fell by 5% in 1981 due to a drop in U.S. demand as a result of the continued availability of competitively priced natural gas and alternative fuels in U.S. markets. Actual natural gas exports, as a percentage of maximum authorized volumes under export licences (which increased by 14% from 1980 to 1981), declined from 69% in 1980 to 58% in 1981.

Higher wellhead prices for conventional oil and natural gas offset the impact of lower production levels so that industry upstream revenues advanced by 3% in 1981 (see Table 1.7). Average wellhead prices for conventional crude oil advanced 27% over the year to reach $133.73 per cubic metre ($21.25 per barrel) by the end of 1981, while the average price for synthetic oil production increased by 5% reflecting higher international crude prices. Average natural gas prices (including the export price flow back to all domestic producers) rose by less than 1% to $2.31 per gigajoule ($2.43 per million Btu).

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(1) For convenience, most of the percentage figures in the text of this report are rounded. For example, 6.4% is presented as 6% in the text, while 6.5% is rounded to 7%. As the percentage changes shown in tables have been calculated on the unrounded data on which the tables are based, the growth rates shown may differ slightly from figures calculated on the rounded amounts shown in the tables.

Table 1.1
PETROLEUM AND NATURAL GAS
SUPPLY AND DEMAND SUMMARY(1)

	1980	1981	Change
	(thousands m^3/day)		(%)
PETROLEUM(2)			
Production(3)	280	257	(8.2)
Net Imports(4)	18	19	5.6
Consumption	300	283	(5.7)
	(billions m^3/year)		
NATURAL GAS			
Production	70	68	(3.0)
Net Exports	23	22	(4.8)
Consumption	45	43	(4.7)

NOTES:

(1) The figures in the table do not balance because industry's own use (e.g. refinery fuel) and inventory changes are not included.

(2) Petroleum includes conventional crude oil and synthetic crude. It also includes natural gas liquids (propane, butane and ethane) derived from gas plants and gas reprocessing plants.

(3) The production figures reflect the crude oil production cutbacks of 9540 m^3/d (60 000 b/d) on March 1 and a further similar amount implemented on June 1, 1981, under the Alberta Maximum Petroleum Production Regulations. Alberta production of crude oil was restored to normal levels following the September 1, 1981 energy agreement between the federal and Alberta governments.

(4) The petroleum import figures are net of exports of crude oil, natural gas liquids and refined product exports. On a gross basis, crude oil imports (including exchange receipts) in 1980 and 1981 were 87 000 and 88 000 m^3/d (547 000 and 554 000 b/d) respectively, or 29 and 31% of domestic consumption in those periods.

Financial Performance

Table 1.2 presents data on industry financial performance on total operations in 1981. Revenues on total operations increased by nearly $9 billion, or 21%, to $51 billion. Of the $9 billion increase in industry revenues, a total of $5 billion was accounted for by increased government levies and taxes (excluding income taxes).

The Petroleum Compensation Charge (PCC) increased both revenues and deductions against revenues by $3.3 billion. The PCC (see page 18) is a federal levy on crude oil processed by Canadian refiners. The purpose of this levy, which is passed on in the selling price to consumers, is to equalize the cost of oil to consumers in all parts of Canada. This is done by paying both oil importers and those domestic producers of synthetic oils receiving special prices (i.e. prices higher than the wellhead price for conventional oil) an amount sufficient to reduce the cost of the oil that they import or produce to the average cost of Canadian oil to all Canadian refiners. As noted later (page 45), the federal government incurred a deficit on the PCC in both 1980 and 1981 as payments to the petroleum industry exceeded collections under the PCC levies in both years.

The Petroleum and Gas Revenue Tax (PGRT), which accounted for $924 million of the increased deductions against revenues, is a federal tax (not deductible for income tax purposes) on revenues and royalty income from oil and gas production. This tax, which was introduced in the NEP and subsequently modified by the various federal-provincial energy agreements in the second half of 1981, came into effect on January 1, 1981.

Total interest expenses charged to operations by PMA reporting companies rose by 114% to reach more than $1.7 billion in 1981. Of this total, Canadian controlled companies accounted for nearly $1.4 billion, up 140% from 1980. Much of this increase can be attributed to the more than doubling of debt incurred by these companies in 1981, primarily as a result of raising funds for acquisitions.(1)

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(1) In addition to the interest charges expensed, the PMA estimates that some $317 million in interest costs were capitalized by reporting companies (almost all of them Canadian controlled) in 1981, up nearly 100%. Generally, interest charges are capitalized in the preproduction or construction stage in order to provide for a better match between the costs associated with capital assets and the revenue streams anticipated from these assets. Only a portion of these capitalized charges would be written off against income each year.

Table 1.2
OVERVIEW OF TOTAL OPERATIONS

	1980	1981	Change
	($ millions)		(%)
GROSS REVENUES	41491	47124	13.6
Petroleum Compensation Charge(3)	862	4124	378.4
TOTAL REVENUES(1)	42353	51248	21.0
less Operating and Related Costs(2)	22215	26532	19.4
Interest Expense	816	1749	114.3
Royalties and Other Taxes(3)	6831	7650	12.0
Petroleum Compensation Charge(4)	862	4124	378.4
Petroleum and Gas Revenue Tax(5)	-	924	-
Non-cash Charges(6)	3361	3744	11.4
TOTAL DEDUCTIONS	34086	44723	31.2
INCOME BEFORE INCOME TAXES	8267	6525	(21.1)
less Current Income Tax	2075	2186	5.4
Deferred Taxes	1512	1227	(18.8)
NET INCOME	4681	3112	(33.5)

NOTES:

(1) Total revenues include gross sales from operations as well as other revenues not related to operations. Other revenues accounted for about 4% of total revenues in both periods.

(2) Operating and related costs include lifting costs, transportation costs, refining and marketing costs, raw material costs, the cost of imported oil valued at domestic prices (i.e. at import prices less PCC payments received by industry), expensed overhead charges, and other general business expenses.

(3) Includes royalties paid to the Crown and freeholders as well as sales and excise taxes paid to all levels of government. Some reporting companies included provincial gasoline taxes in this category and in revenues, while other companies netted these taxes out.

(4) The Petroleum Compensation Charge (PCC) is a federal levy imposed on all refiners and direct importers of petroleum in Canada. This figure includes the Canadian Ownership Charge. The purpose of this levy, which is passed on in the selling price to consumers, is to equalize the cost of oil to consumers in all parts of Canada.

(5) The Petroleum and Gas Revenue Tax (PGRT) is a federal tax, which is applicable to the upstream sector of operations only.

(6) Non-cash charges are depreciation, depletion, amortization and other write-offs. They have been adjusted to include also exploration and development expenses charged to operations.

Companies usually raise debt on the strength of their total operations and, therefore, it is sometimes difficult for them to allocate the interest charges on this debt to individual sectors of their operations (e.g. upstream, downstream, etc.). As indicated in subsequent sections of this report (page 20), the non-allocation by some reporting companies of their interest charges to the various sectors of operations causes difficulties in interpreting the relative financial performance of different sectors.

Table 1.2 indicates that total deductions from revenues rose by 31% to almost $45 billion. As total deductions increased more rapidly than total revenues (up 21%), income before income taxes declined by 21% to $6.5 billion. Current income taxes rose by 5% to $2.2 billion while deferred taxes dropped by 19% to $1.2 billion.

Net income, or after-tax profits, on total operations declined by 34% to $3.1 billion. As noted later (page 18), nearly $1.3 billion of the $1.6 billion reduction in industry net income was due to the decline in profits derived from operations in the upstream (exploration, development and production) sector.

The foreword to this survey noted that the net income figures reported to the PMA by the petroleum industry reflect the recommendation of the Canadian Institute of Chartered Accountants (CICA) with respect to accounting for government Petroleum Incentives Program (PIP) grants. In brief, the CICA accounting guideline requires that PIP grants be reflected as a reduction of the exploration and development expenditures to which they relate. Thus, PIP grants relating to expenditures that are capitalized would be brought into income during the same years in which the expenditures are amortized.(1) In the case of expenditures that are immediately written off against income (e.g. unsuccessful exploration expenditures for a company on the successful efforts accounting method), the corresponding PIP grants would be recognized as income in the same year.

Table 1.3 presents data on net income on total operations for the five groups of companies considered in this report. The rate of decline in net income for the integrated companies (all foreign controlled) was marginally below that for the overall industry. The foreign controlled senior companies experienced a net income decline of 44%, in excess of the industry average of 34%, while junior companies (both Canadian and foreign controlled) recorded lower decreases than the industry average. Taken as a whole, the net income of Canadian controlled firms declined marginally less (32%) than that of foreign controlled firms (34%).

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(1) Companies that were eligible for PIP grants in 1981 could, for cash management purposes, offset their PGRT liabilities against estimated PIP grants. Table 2.5 presents an estimate of the amount of this offset.

Table 1.3
NET INCOME ON TOTAL OPERATIONS
BY COMPANY GROUP(1)

	1980	1981	Change	Percentage of Total 1980	Percentage of Total 1981
	($ millions)		(%)		
Integrated Companies	2391	1613	(32.6)	51.1	51.8
Senior Companies					
Canadian Controlled	1360	906	(33.4)	29.1	29.1
Foreign Controlled	517	290	(43.9)	11.0	9.3
Junior Companies					
Canadian Controlled	291	216	(25.8)	6.2	7.0
Foreign Controlled	122	88	(28.0)	2.6	2.8
TOTAL INDUSTRY	4681	3112	(33.5)	100.0	100.0
Canadian Controlled	1651	1121	(32.1)	35.3	36.0
Foreign Controlled	3030	1991	(34.3)	64.7	64.0

NOTE:

(1) Appendix III, Statistical Schedule A presents more detail. As noted in the foreword to this report, some PMA reporting companies have been transferred to different company groups as a result of takeover activity in 1981. In order to provide for comparable year-over-year results, data for any such company for both 1980 and 1981 were allocated to the new group.

The 1980 Monitoring Survey indicated that petroleum industry net income grew strongly over the decade of the 1970s compared to that of other non-financial industries in Canada. As shown in Table 1.4, the net income of the petroleum industry (as defined by Statistics Canada) in 1972 was equal to 18% of that of all other non-financial industries, whereas by 1980 the comparable figure had grown to 43%. In 1981, the net income of the petroleum industry declined so that it equalled 34% of the total for other non-financial industries--somewhat less than the equivalent ratio for 1979. As shown, the manufacturing and mining industries also incurred profit declines in 1981. Taken together, the drop in net income for all non-financial industries (excluding petroleum) from 1980 to 1981 was 18% compared to the 35% drop for the petroleum industry.

Table 1.4
NET INCOME VARIOUS INDUSTRIES(1)

	1972	1975	1979	1980	1981
	($ millions)				
(1) Manufacturing(2)	2211	3584	5588	5844	4995
(2) Mining(2)	319	702	1972	2076	709
(3) Other Non-financial(2)	1922	2708	3319	3665	3776
(4) TOTAL NON-FINANCIAL (excluding petroleum)	4452	6994	10879	11585	9480
(5) Petroleum	804	1700	4060	5005	3247(3)
(6) TOTAL NON-FINANCIAL (including petroleum)	5256	8694	14939	16590	12727
(7) Line 5 as a % of 6	15.3	19.6	27.2	30.2	25.5
(8) Line 5 as a % of 4	18.1	24.3	37.3	43.2	34.3

NOTES:

(1) SOURCE: Statistics Canada 61-003, Industrial Corporations Quarterly. The figures shown are for companies having $10 million or more in total assets. For the years 1972 and 1975, the figures are based on a larger sample, which includes all companies with $10 million and more in assets plus a sample of smaller companies.

(2) The manufacturing, mining and other non-financial sectors exclude the petroleum component of these industries.

(3) The Statistics Canada estimate of $3.2 billion for total petroleum industry net income for 1981 compares closely to the PMA figure of $3.1 billion (Table 1.2).

Rates of return on shareholders' equity and on capital employed for both the petroleum industry and for other non-financial industries are presented in Table 1.5 for the years 1972, 1980 and 1981. The rate of return on shareholders' equity for the petroleum industry rose from 10% in 1972, which mirrored the average for all non-financial industries at that time, to 22% in 1980. Using capital employed as the base, the rate of return for the petroleum industry rose from 8% in 1972 to 14% in 1980. On both measurement bases, the rate of return for the petroleum industry in 1980 exceeded that for the other non-financial industries by a substantial amount. As shown, rates of return for both the petroleum industry and for all other non-financial industries taken together declined substantially from 1980 levels and were approximately equal in 1981.

Table 1.5
RATE OF RETURN FOR VARIOUS INDUSTRIES(1)

	Rate of Return on Shareholders' Equity(2)			Rate of Return on Capital Employed(3)		
	1972	1980	1981	1972	1980	1981
		(%)			(%)	
(1) Manufacturing	11.0	15.1	11.3	8.2	11.6	9.1
(2) Mining	5.9(4)	18.9	5.9(4)	4.8(4)	13.2	4.8(4)
(3) Other Non-financial	11.5	13.3	12.5	7.4	8.8	9.2
(4) TOTAL NON-FINANCIAL (excluding petroleum)	10.5	15.0	11.0	7.7	10.7	8.6
(5) Petroleum	10.4	21.7	11.7	8.4	14.3	8.3
(6) TOTAL NON-FINANCIAL (including petroleum)	10.5	16.5	11.1	7.8	11.6	8.4

NOTES:

(1) SOURCE: Statistics Canada 61-003, Industrial Corporations Quarterly.

(2) Return on equity measures the rate of return on shareholders' investment and is a common measure of profitability. It is often used to compare the performance of companies which may vary greatly by type and by size.

(3) Capital employed is here defined as total assets less current liabilities. The rate of return on capital employed includes an adjustment for the after tax interest expense on borrowed funds.

(4) The relatively low figure for the mining industry in 1972 and 1981 is due to extraordinary losses by some members of the industry in those years.

Table 1.6 presents semi-annual statistics on net income for upstream, downstream and petroleum-related (upstream plus downstream) operations. The figures in the table illustrate the sharp decline in upstream net income in 1981, confirming the trend that was identified provisionally in the 1980 Monitoring Survey (page 9). Upstream net income in the first and second halves of 1981 was 50 and 39% respectively below that for the comparable periods in 1980. The figures indicate that upstream after-tax profits peaked in the first half of 1980.

Table 1.6
SEMI-ANNUAL NET INCOME(1)

	Upstream		Downstream(2)		Petroleum-related	
	($ millions)	(% change)	($ millions)	(% change)	($ millions)	(% change)
1978 (I)	935		107		1042	
1978 (II)	1003		171		1174	
1979 (I)	1064	13.8(3)	513	379.4	1577	51.3
1979 (II)	1370	36.6	527	208.2	1897	61.6
1980 (I)	1459	37.1	665	29.6	2124	34.7
1980 (II)	1444	5.4	807	53.1	2251	12.7
1981 (I)	735	(49.6)	792	19.1	1527	(28.1)
1981 (II)	886(4)	(38.6)	576	(28.6)	1462	(35.1)

NOTES:

(1) Minor adjustments have been made to some figures in order to accommodate restatements of earlier financial results by a few reporting companies.

(2) Downstream net income has been adjusted for several unusual items by allocating the effect equally to the two halves of the years in which they occurred.

(3) Percentage changes are calculated from the same period one year earlier. For example, the 13.8% increase shown for upstream net income in the first half of 1979 represents the rate of increase over the first half of 1978.

(4) The higher level of upstream net income in the second half of 1981 as compared to the first half of that year may be partially due to changes in the method of accounting for depletion (i.e. from a unit-of-production basis to a forecasted revenue basis) by some companies. Since companies were not required to indicate changes in accounting methods on the 1981 questionnaire, it is not possible to estimate the impact of such a change.

Downstream net income in the first half of 1981 was up 19% over the corresponding period of 1980. As noted later (page 18), more than 40% of the first half 1981 profits on downstream operations was due to inventory gains resulting from increases in the Petroleum Compensation Charge (PCC). In contrast to the first half performance, downstream profits in the second half of 1981 were 29% below those of the corresponding period in 1980. The downturn in the second half of 1981 was due to declining demand for petroleum products, higher operating costs, and inventory losses due to reductions in the PCC (page 19).

Net Income by Sector of Operations

Table 1.7 presents financial data for the four major sectors of industry operations--upstream, downstream, other Canadian operations and foreign operations. In the upstream sector, industry revenues from operations increased by 3% to $16.5 billion in 1981. The increased revenues were due to higher prices for crude oil and natural gas although, as noted earlier, lower production levels diminished the effect of these higher prices on revenues.

Total deductions on upstream operations, up by 16% to $12.7 billion, rose more rapidly than revenues. The level of royalty payments and taxes (other than income taxes and the PGRT) on upstream operations remained constant at $4.9 billion in 1981, and constituted the largest component on total deductions.

Operating and related costs increased by 14% and accounted for $3.4 billion of total upstream deductions. Preliminary estimates suggest that total upstream operating costs (exclusive of related costs) increased by 10% over 1980.(1) These increased operating costs combined with the lower level of production for oil and gas(2) indicate that per unit operating costs increased by more than 15% in 1981.

Interest charges expensed to operations in the upstream sector rose to nearly $700 million, a 43% increase over the estimated 1980 level of about $500 million. The PMA questionnaire for 1980 did not request separate data on interest expenses--thus, figures in this report on 1980 interest charges are estimates.

Total taxes on upstream operations remained relatively constant with an increase in current taxes paid (up 36%) being offset by a decline in deferred taxes claimed (down 32%). The increase in current taxes paid on upstream operations contrasts with the 25% decline in income before

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(1) A recently instituted joint government-industry working group is in the process of collecting comprehensive data on upstream operating costs. Results from this survey, which should be published in the near future, will provide additional detail on the costs of upstream operations.

(2) Detailed 1981 production data for PMA companies are shown in Statistical Schedule F of Appendix III.

Table 1.7

OVERVIEW OF OPERATIONS BY SECTOR(1)

	1980	1981	Change	1980	1981	Change
	($ millions)		(%)	($ millions)		(%)
	UPSTREAM OPERATIONS			DOWNSTREAM OPERATIONS		
GROSS REVENUES				22706	25545	12.5
PCC				862	4124	378.4
TOTAL REVENUES	16076	16535	2.9	23568	29669	25.9
less Operating and Related Costs	2913	3438	18.0	17665	19727	11.7
Interest Expense	487(e)	696	42.9	184(e)	279	51.6
Royalties and Taxes	4935	4928	(0.1)	1813	2629	45.0
PCC	-	-	-	862	4124	378.4
PGRT	-	924	-	-	-	-
Non-cash Charges(2)	2664	2738	2.8	400	441	10.2
TOTAL DEDUCTIONS	10999	12724	15.7	20924	27200	30.0
INCOME BEFORE TAXES	5078	3811	(25.0)	2644	2469	(6.6)
less Current Income Tax	1038	1408	35.6	1031	845	(18.0)
Deferred Taxes	1151	782	(32.1)	159	256	61.3
NET INCOME	2889	1621	(43.9)	1454	1368	(5.9)
	OTHER CANADIAN OPERATIONS(3)			FOREIGN OPERATIONS		
TOTAL REVENUES	1383	3132	126.4	1325	1911	44.2
less Operating and Related Costs	1014	2414	138.1	624	952	52.6
Interest Expense	108(e)	646	498.1	37(e)	128	245.9
Royalties and Taxes	4	2	(44.4)	79	92	15.8
Non-cash Charges(2)	78	138	76.1	219	426	95.1
TOTAL DEDUCTIONS	1204	3200	165.8	959	1598	66.6
INCOME BEFORE TAXES	179	(68)	(138.0)	367	313	(14.7)
less Current Income Tax	(27)	(113)	321.5	32	46	41.4
Deferred Taxes	43	35	(19.3)	159	154	(2.9)
NET INCOME	163	10	(93.5)	176	113	(35.6)

NOTES:

(1) Appendix III, Statistical Schedule A presents further detail.

(2) Includes E and D expenditures charged to operations.

(3) Includes such activities as drilling services, coal and uranium mining, metal mining, and other non- petroleum related activities.

taxes on these operations. The major part of this anomaly is due to the PGRT, which is not deductible for tax purposes. A second explanatory factor is that declining capital expenditures in 1981 resulted in reduced deductions for purposes of calculating current income taxes. Further, the movement from a tax based (i.e. phasing out of depletion, removal of super-depletion) to a grant based (PIP) incentive system resulted in reduced deductions and increased taxable income for some companies.

Net income on upstream operations declined by 44% to $1.6 billion. The PGRT accounted for about three-quarters of the $1.3 billion drop in upstream profits. In the absence of this tax, upstream after-tax profits in 1981 would have been $2.5 billion, a decline of 12%. Other factors, such as higher operating costs and increased interest charges, also contributed to the decline in upstream net income.

In the downstream sector, revenues from operations were up by $6.1 billion, or by 26%, to nearly $30 billion. Of the $6.1 billion increase in revenues, $4.1 billion, or more than 67%, was accounted for by higher government levies that were passed through to consumers in the form of higher prices. In the absence of these higher levies, downstream revenues would have risen by only 13%.

Net income on downstream operations declined by 6% to $1.4 billion. Nearly 60% of downstream net income in 1981 was reported in the first half of that year (see Table 1.6). In comparison, the average ratio for the years 1978-80 was 44%. The weak performance of the downstream sector in the second half of 1981 was due primarily to declining demand for petroleum products resulting in strong competitive pressures as individual companies attempted to maintain their previous volumes of sales. The result was an erosion in profit margins, as companies discovered that they were unable to pass on to consumers the full amount of cost increases, both crude related and non-crude related.

Changes in the Petroleum Compensation Charge (PCC) and related charges collected in a similar manner had a major impact on downstream net income in both 1980 and 1981.(1) The PCC is applied to importers of refined products and to all Canadian refiners based on the receipt of crude oil at the refinery gate. If market conditions permit, refiners are able to pass increases in the PCC on to consumers immediately.(2) This means that the price of products sold out of inventory after an increase in the PCC (i.e. products whose cost does not include the higher PCC) can be raised and thus yield an inventory profit when sold. Conversely, decreases in the PCC result in a loss to refiners on the sales of products held in inventory at the time of the reduction in the charge.

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(1) Changes to the PCC in both 1980 and 1981 are summarized in Appendix V to this report.

(2) In contrast to passing through increases in the PCC immediately, refiners must wait 60 days before passing on <u>wellhead</u> price increases to consumers.

The PMA has estimated after-tax inventory gains for reporting companies for both 1980 and 1981 using data on physical levels of crude and product inventory on hand at the month's end prior to the introduction of the various changes in the PCC. These estimated after-tax gains, as well as the loss from the November 30, 1981 reduction in the PCC, are shown in Table 1.8. The table shows that if the impact of inventory gains and losses due to changes in the PCC is removed, downstream net income in 1981 declined by 18%, as compared to the 6% decrease in unadjusted downstream profits.

Table 1.8
ADJUSTED DOWNSTREAM NET INCOME

	1980	1981	Change
	($ millions)		(%)
Unadjusted downstream net income	1454	1368	(5.9)
less gain from PCC increases	84	334	297.6
loss from PCC decrease	-	(93)	-
Adjusted net income	1370	1127	(17.7)

Since inventory profits on PCC increases are taxable, the amount of cash retained by the industry after the payment of taxes on these profits is not sufficient to replace volumes sold out of inventories when PCC increases. Therefore, for each increase in the PCC, the industry has to raise funds either from revenues generated by operations or from external sources (e.g. debt) to replace inventories at the higher cost. In the event of a decrease in the PCC, the industry incurs a loss on products sold out of inventory (adjusted for the tax savings as a result of the revenue loss), but benefits from a reduced working capital requirement. The impact of PCC changes on the amount of working capital required by the industry to carry on its operations is discussed later in this report (see page 34).

After-tax profits on other Canadian operations dropped from $163 million to $10 million, a decrease of 94%. The major reason for this large drop in profits relates to the allocation of substantial amounts of interest charges to this sector of operations by several reporting companies, including some companies involved in takeover activity.

Table 1.7 shows that the amount of interest charges allocated to the other Canadian operations sector rose by nearly 500% to reach $646 million in 1981. Thus, the other Canadian operations sector accounted for about 6% of total industry revenues in 1981, but 37% of total interest expense charged to operations. This disproportionately large allocation of interest makes it difficult to assess the sector's

financial performance. To the extent that portions of these interest charges could be allocated to the upstream and downstream sectors, net income and cash flow for these sectors would be lower than indicated in this report.

After-tax profits on foreign operations declined by 36% to $113 million. A number of factors accounted for this decrease. One company, pursuant to U.S. Security and Exchange Commission (SEC) accounting rules, wrote down its U.S. assets in 1981 thereby contributing substantially to a net income loss of $10.9 million. In addition, the suspension of some U.S. metal mining operations in light of softening world prices contributed to the decline in after-tax profits.

II. SOURCES OF FUNDS

Table 2.1 presents summary data on industry sources of funds. Total sources of funds available to the industry rose by 46% to $22.4 billion in 1981. Funds generated by operations, or internal cash flow, declined by 15% to $8.1 billion. In contrast, external sources of funds rose by 147% to $14.3 billion. New long-term debt, most of which was raised by Canadian controlled companies for purposes of takeovers or acquisitions, increased by more than 240% to $9.4 billion and was the most important component of the increase in external sources of funds. Government PIP grants, a new source of industry funding, totalled $670 million for PMA reporting companies in 1981.

Internal Sources of Funds

Internal sources of funds (internal cash flow) indicate the amount of cash that the industry raises directly from its operations. They comprise net income, deferred taxes, E&D expenditures written off against current income and all the non-cash items (depreciation, depletion and amortization) that are expensed in the reporting period but do not require an actual financial outlay in that period.

As shown in the table, the net income component of internal cash flow declined by 34% to $3.1 billion. In contrast, non-cash items and related charges were up by 2% to $5 billion. Of the $5 billion in non-cash and related items, the more significant components were $1.7 billion in exploration and development expenditures charged to operations (i.e. unsuccessful drilling efforts), $1.2 billion in depreciation, and $1.2 billion in deferred taxes.

Table 2.2 shows the distribution of internal cash flow for the four sectors of industry operations. The 23% decline in cash flow on upstream operations was the predominant reason for the 15% decline in cash flow on total operations. As indicated, internal cash flow from upstream operations accounted for 64% of cash flow from total operations in 1981 compared to 70% in 1980. Relatively small increases in the amount of cash flow on both downstream operations and foreign activities only partially offset the decline in cash flow from upstream and other Canadian operations.

Table 2.1
SUMMARY OF SOURCES OF FUNDS

	1980	1981	Change	Percentage of Total 1980	Percentage of Total 1981
	($ millions)		(%)		
Internal Sources					
Net Income	4681	3112	(33.5)	30.5	13.9
Non-cash Items(1)	4872	4971	2.0	31.7	22.2
Total Internal Sources	9553	8083	(15.4)	62.2	36.1
External Sources					
New Long-term Debt(2)	2743	9398	242.6	17.9	42.0
New Equity	1559	1826	17.1	10.2	8.1
PIP Grants	-	670	-	-	3.0
Working Capital Decrease	677	1126	66.2	4.4	5.0
All Other Sources(3)	820	1299	58.4	5.3	5.8
Total External Sources	5799	14319	146.9	37.8	63.9
TOTAL SOURCES	15352	22402	45.9	100.0	100.0

NOTES:

(1) This source includes items expensed in the reporting period that do not necessarily require an actual financial outlay in that period, namely, depreciation, depletion and amortization, as well as exploration and development expenditures written-off against current income. Deferred taxes are also included.

(2) The figures shown represent gross sources of funds. For example, the figure of $9.4 billion represents the net amount of new long-term debt raised by those reporting companies that indicated increases in debt in 1981. Some companies reported a net decrease in their long-term debt (retirement of debt), which is shown as a use of funds in Table 3.1.

(3) The category 'All Other Sources' includes provincial grants other than PIP, proceeds from capital leases, proceeds from sales of assets such as property and plant equipment, and prepayment for deferred production (natural gas).

Table 2.2
DISTRIBUTION OF INTERNAL CASH FLOW BY SECTOR OF INDUSTRY ACTIVITY

	1980	1981	Change	Percentage of Total 1980	1981
	($ millions)		(%)		
Upstream	6704	5141	(23.3)	70.1	63.6
Downstream	2013	2065	2.6	21.1	25.5
Other Canadian Operations	284	183	(35.4)	3.0	2.3
Foreign Operations	553	694	25.5	5.8	8.6
TOTAL INTERNAL CASH FLOW	9553	8083	(15.4)	100.0	100.0

Table 2.3 presents data on internal cash flow and on interest charges, both expensed and capitalized, for the various company groups. Column 1 of the table shows internal cash flow from total operations by company group. Column 2 shows the total interest charges (both expensed and capitalized), while column 3 represents internal cash flow plus expensed interest charges only (capitalized interest is not added back because it is not deducted as an expense in computing internal cash flow). This 'adjusted' cash flow as shown in column 3 indicates the total internal sources of funds that are available to each company group to meet its interest payments and other cash outlays.

Column 4 of the table shows the ratio of adjusted cash flow (column 3) to total annual interest charges (column 2). This ratio demonstrates the relative ability of the various company groups to cover their total interest charges from internally generated sources of funds. As shown, the adjusted cash flow for the Canadian controlled companies considered as a group was sufficient to cover their total interest charges 2.6 times. In other words, interest charges accounted for about 38% of the internal cash flow of these companies in 1981. In marked contrast, the foreign controlled group was able to cover its interest charges nearly 14 times from internal cash flow.

The table highlights the difficulties facing the Canadian controlled companies of the petroleum industry as a result of those companies' reliance upon debt capital as a means of financing long-term expenditures. The continued absorption of more than one-third of internal (adjusted) cash flow by annual interest charges may force a reduction in the level of future capital expenditure programs for this segment of the industry. However, an increased annual flow of both federal and Alberta grants as the PIP program matures (see Table 2.5) and the revenue and tax changes announced by Alberta and by the federal government in April and May of 1982 respectively should assist by increasing the overall level of funds available to the industry.

Table 2.3
INTERNAL CASH FLOW AND INTEREST EXPENSE
BY COMPANY GROUP AND COMPONENT

	1	2	3	4
	Internal Cash Flow	Total Interest Charges (1)	Adjusted Cash Flow (2)	Ratio of Column 3 to Column 2
	($ millions)			
Integrated	3765	230	3995	17.4
Senior Companies				
Canadian Controlled	2177	1228	3171	2.6
Foreign Controlled	984	35	1019	29.1
Junior Companies				
Canadian Controlled	857	446	1231	2.8
Foreign Controlled	299	126	415	3.3
TOTAL INDUSTRY	8083	2065	9831	4.8
Canadian Controlled	3035	1674	4402	2.6
Foreign Controlled	5048	391	5429	13.9

NOTES:

(1) In addition to the $1.7 billion of interest charges expensed to operations in 1981, an estimated total of $317 million was capitalized. Most of this total was accounted for by Canadian controlled companies, with $233 million and $72 million accounted for by Canadian controlled senior and Canadian controlled junior companies respectively.

(2) Adjusted cash flow represents internal cash flow plus expensed interest charges. Capitalized interest charges are not included because they are not deducted as an expense in computing internal cash flow.

External Sources of Funds

In addition to funds from internal cash flow, the industry raised $14.3 billion from external sources as presented in Table 2.1. External sources of funds represented 64% of total sources, in marked contrast to the 38% contribution in 1980. The $8.5 billion growth in these sources is primarily accounted for by an increase of $6.6 billion in new long-term debt. The remaining increase in external sources is comprised of $0.7 billion in government PIP grants, a $0.3 billion increase in equity, $0.5 billion working capital decrease, and nearly $0.5 billion from other sources.

The $9.4 billion of long-term debt raised in 1981 was primarily for purposes of acquisitions and takeovers of petroleum-related companies and assets by Canadian controlled companies. These latter companies accounted for $8.2 billion, or 87%, of the total new long-term debt.

The PMA has estimated the amount of new long-term debt raised in both 1980 and 1981, which was associated with takeover or acquisition activity, to be $0.7 billion and $4.9 billion respectively. If these amounts are subtracted from those indicated for long-term debt in Table 2.1, the adjusted figures for new long-term debt would be $2.0 billion and $4.5 billion in 1980 and 1981 respectively. This would represent a growth rate of 125% as compared to the 243% shown in the table.

An important new source of funds for the industry in 1981 was government PIP grants. One of the stated purposes of the NEP is to increase the Canadian ownership of the oil and gas industry. To this end, direct incentives are to be paid in the form of PIP grants to qualifying enterprises carrying out specified oil and gas exploration, development, and production activities in Canada. The level of these incentives varies according to the area in which exploration and development occur and is higher for those enterprises that are Canadian controlled and have specified levels of Canadian ownership. The Government of Alberta will administer and pay the incentives under the program for activities within Alberta and the federal government will administer the program elsewhere in Canada.

Table 2.4 indicates that PMA reporting companies estimated their entitlement to PIP grants to total $670 million in 1981. Canadian controlled companies accounted for $563 million, or 84%, of total PIP grants reported by PMA companies.(1) Of the total of $670 million, amounts of $470 million and $200 million are estimated to be paid by the federal and Alberta governments respectively.

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(1) In addition to the PIP grants shown in Table 2.4, smaller companies not reporting to the PMA, as well as non-corporate entities such as drilling funds, will also be eligible for PIP grants in 1981. Smaller incorporated companies not reporting to the PMA are estimated to account for an additional $140 million in PIP grants. Preliminary results of a special study on drilling funds currently being completed by the PMA suggest that drilling funds will be eligible for perhaps $90 million of PIP grants in 1981.

Table 2.4
ESTIMATED PIP GRANTS
PMA REPORTING POPULATION

Expenditure	B.C.	Alberta	Sask.	Other Provinces	Canada Lands	Total
			($ millions)			
Exploration	16	146	2	-	445	609
Development	4	53	2	1	-	60
Production	-	1	-	-	-	1
TOTAL	20	200	4	1	445	670
Canadian Controlled	20	200	4	1	338	563
Foreign Controlled	-	-	-	-	107	107

As noted earlier in this report (page 11), companies were able to offset (for cash management purposes) their estimated PIP grant accruals against their PGRT liabilities. Table 2.5 illustrates the net impact of this offset by presenting data on estimated PIP grants (column 1) and PGRT liabilities (column 2) for each company group in the PMA reporting population. Column 3 of the table shows that the net impact of PIP and PGRT, for the industry as a whole, is a reduction of $254 million in upstream sources of funds in 1981.

Column 4 shows that the PIP/PGRT offset, calculated on a company-by-company basis for those firms in a position to make such an offset, totalled $319 million. This estimated offset is less than the maximum potential offset of $670 million because the amount of PIP grants for some companies, almost all of them Canadian controlled, exceeded their PGRT liabilities. The net offset was markedly different between the Canadian controlled and foreign controlled component of the industry, with the former group offsetting two-thirds of their PGRT liabilities ($215 million of $329 million) and the latter group about 17% ($104 million of $595 million).

As noted above, on an overall industry basis, governments' contribution to industry cash sources of $670 million of PIP grants was offset by $924 million in PGRT for a net deficit of $254 million. This net deficit was distributed between a $234 million surplus of PIP over PGRT for Canadian controlled companies and a $488 million deficit for foreign controlled firms. These figures reflect a reversal of trends under the previous system of providing tax incentives related to exploration and development expenditures which tended to favour the larger, and mostly foreign controlled, firms.

Table 2.5
NET IMPACT OF PIP AND PGRT
ON UPSTREAM SOURCES OF FUNDS

	1	2	3	4
	TOTAL PIP GRANTS	PGRT	IMPACT ON UPSTREAM SOURCES OF FUNDS	POTENTIAL COMPANY OFFSET PIP/PGRT (1)
	($ millions)			
Integrated	84	384	(300)	84
Senior Companies				
Canadian Controlled	463	259	204	170
Foreign Controlled	20	171	(151)	20
Junior Companies				
Canadian Controlled	100	70	30	45
Foreign Controlled	3	40	(37)	-
TOTAL INDUSTRY	670	924	(254)	319 (2)
Canadian Controlled	563	329	234	215
Foreign Controlled	107	595	(488)	104

NOTES:

(1) The potential offset shown in column 4 is less than the amount of PIP grants shown in column 1. This is because the amount of PIP grants for some companies (almost all of them Canadian controlled) exceeded their PGRT liabilities. The figures in column 4 represent the maximum amount of PIP/PGRT offset for those companies in a position to make such an offset.

(2) The $319 million offset indicates that, if PIP could have been offset against PGRT for purposes of determining net income in financial statements, net income for the overall industry would have been up to $319 million higher. The actual figure would be somewhat less, since that portion of PIP associated with unsuccessful E&D expenditures (for companies on the successful efforts accounting system) would have been reflected in 1981 net income. It is not possible to determine this latter amount with precision, but it is probably only a small portion of the total.

III. USES OF FUNDS

A summary of the industry's uses of funds is presented in Table 3.1. Total uses of funds rose by 46% to about $22.4 billion. Capital expenditures accounted for more than one-half of the total uses of funds, and increased to $11.6 billion, up 21%. The category 'All Other Uses', which consists mainly of funds used for acquisitions, rose by over 300% to reach $6.6 billion. The $5 billion increase in this category accounted for 70% of the year-over-year rise in total uses of funds.

Table 3.1
SUMMARY OF USES OF FUNDS

	1980	1981	Change	Percentage of Total 1980	Percentage of Total 1981
	($ millions)		(%)		
Capital Expenditures in Canada	8448	9844	16.5	55.0	43.9
Foreign Capital Expenditures	1151	1728	50.1	7.5	7.7
TOTAL CAPITAL EXPENDITURES	9598	11571	20.6	62.5	51.7
Dividends	940	1119	19.0	6.1	5.0
Reduction of Equity	160	239	48.8	1.0	1.1
Decrease in Long-term Debt	610	661	8.2	4.0	2.9
Working Capital Increase	2416	2189	(9.4)	15.7	9.8
All Other Uses	1628	6623	307.0	10.6	29.5
TOTAL ALL USES	15352	22402	45.9	100.0	100.0

Capital Expenditures

Table 3.2 presents detail on industry capital expenditures. As shown, total upstream capital expenditures in Canada declined by 3%, or by $200 million, to $6.7 billion. This decline was made up of a $593 million decrease in spending by foreign controlled companies (down 15%), which was partially offset by a $376 million increase (up 13%) by Canadian controlled companies. PIP grants to Canadian controlled companies (Table 2.4) amounted to $563 million, or 17% of their total 1981 upstream spending of $3.3 billion. For foreign controlled companies, PIP grants of $107 million amounted to about 3% of their total upstream expenditures of $3.4 billion. If capital expenditures are considered net of PIP, Canadian controlled and foreign controlled companies registered declines in upstream capital spending of 6 and 18% respectively.

Table 3.2
CAPITAL EXPENDITURES--SUMMARY(1)

	1980	1981	Change	Percentage of Total 1980	Percentage of Total 1981
	($ millions)		(%)		
Exploration(2)	4135	3766	(8.9)	43.1	32.5
Development	1036	1031	(0.5)	10.8	8.9
Production	1095	1381	26.1	11.4	11.9
Non-conventional(3)	657	528	(19.6)	6.8	4.6
TOTAL UPSTREAM(4)	6923	6706	(3.1)	72.1	58.0
Downstream	755	1952	158.5	7.9	16.9
Energy Mining	126	348	176.2	1.3	3.0
All Other	643	837	30.1	6.7	7.2
TOTAL CANADIAN EXPENDITURES	8448	9844	16.5	88.0	85.1
Foreign Capital Expenditures	1151	1728	50.1	12.0	14.9
TOTAL CAPITAL EXPENDITURES	9598	11571	20.6	100.0	100.0

NOTES:

(1) A more detailed breakdown of upstream capital expenditures is presented in Appendix III, Schedule C. Appendix III, Schedule D provides additional detail on total capital expenditures.

(2) Expenditures undertaken by drilling funds are not included in the figures shown, except to the extent that some reporting companies owned a portion of a drilling fund. The PMA is currently completing a questionnaire survey of the operations of drilling funds in Canada over the period 1978-81. This study will be published in the near future.

(3) Includes oil sands plants and non-conventional heavy oil projects.

(4) Upstream capital expenditures are recorded in gross terms with no downward adjustment for PIP grants. This procedure is being followed in order to facilitate the comparison of capital expenditures over time. Thus, the $670 million of PIP grants reported by PMA companies for 1981 are included in the upstream capital expenditure figures. The grants themselves are included in Table 2.1 as a source of funds.

The geographic distribution of exploration expenditures in Canada is presented in Table 3.3. Exploration spending on provincial lands declined by 25% to $2.6 billion. These expenditures accounted for 68% of total exploration outlays in Canada in 1981, down from 82% in 1980. In contrast, expenditures in the Canada Lands rose by 67% to $1.2 billion.

Various companies, in their annual reports to shareholders, attributed the decline in upstream expenditures on provincial lands in 1981 to two main factors. The first reason was the uncertainty arising from the lack of agreement between the federal government and the governments of the western producing provinces in the period immediately following the tabling of the NEP and prior to the signing of the various federal-provincial energy agreements in the second half of 1981. The second factor was the lifting in early 1981, by the U.S. federal government, of all price controls on crude oil production in that country. The resulting increase in crude oil prices was a major factor behind the rise in investment by Canadian companies in the United States in 1981 (see below). Although difficult to quantify, domestic and international economic conditions would also have contributed to the decrease in expenditures on provincial lands.

Table 3.3
CAPITAL EXPENDITURES ON EXPLORATION(1)
IN CANADA BY LOCATION

	1980	1981	Change
	($ millions)		(%)
Provinces	3416	2562(2)	(25.0)
Canada Lands	719	1204	67.4
of which:			
Offshore	336	461	
Mainland Territories and Beaufort Sea	299	675	
Arctic Islands	84	68	
TOTAL CANADA	4135	3766	(8.9)

NOTES:

(1) Exploration expenditures comprise three components: land and lease, geological and geophysical, and exploration drilling. Exploration drilling expenditures are by far the most significant of the components and accounted for $2.5 billion, or 68%, of the total 1981 outlay of $3.8 billion. The land and lease and geological and geophysical components accounted for roughly $600 million each of 1981 exploration outlays.

(2) Of the provincial exploration expenditures in 1981, the major components were: Alberta $2154 million, British Columbia $283 million, and Saskatchewan $104 million. A provincial breakdown for 1980 is not available.

The declines in exploration and development expenditures in Canada in 1981 were reflected in reductions in both the number of wells completed and metres drilled. As shown in Table 3.4, the number of exploration and development wells completed in 1981 decreased by 21 and 28% respectively from 1980 levels. The total number of metres drilled declined from 10.6 million in 1980 to 8.0 million, or by 25%.

Table 3.4
WELL COMPLETIONS AND METRES DRILLED IN CANADA(1)

	1980	1981	Change (%)
Well Completions (number of wells)			
Exploratory	3896	3074	(21.1)
Development	5254	3760	(28.4)
Total	9150	6834	(25.3)
Metres Drilled (thousands)			
Exploratory	5391	4256	(21.1)
Development	5230	3735	(28.6)
Total	10621	7991	(24.8)

NOTE:

(1) SOURCE: Nickle's Daily Oil Bulletin. Well completion data shown in the first half 1981 Monitoring Report (p. 26) were overstated, although the period-over-period percentage changes reported were approximately correct.

The decreases in both well completions and metres drilled in 1981 are measured against the record level of exploration and development activity in Canada in 1980. While there were decreases in activity in 1981, the total number of exploration and development wells drilled in that year (6834) is similar to results for 1978 (6800) and 1979 (6810).

Downstream capital expenditures rose by nearly 160% to $2 billion. This increase is largely explained by expenditures by a number of companies on refinery modifications, primarily designed to increase the percentage of light products in refinery output. The $220 million increase in energy mining expenditures was accounted for by outlays on coal mines, mainly by the integrated companies.

Capital expenditures abroad increased by 50% to reach $1.7 billion, with about 60% of these expenditures taking place in the United States. Canadian controlled companies accounted for $1.6 billion, or more than 90%, of total industry capital expenditures abroad in 1981. The Canadian controlled junior companies increased their foreign capital outlays to $833 million, or by 81%. Capital expenditures abroad accounted for nearly 40% of the total capital outlays of this latter group of companies in 1981 compared to 29% in 1980.

In order to place the petroleum industry capital expenditures into perspective, Table 3.5 compares the capital outlays of that industry with other non-financial sectors of the economy. Based on Statistics Canada data, petroleum industry capital expenditures declined from 56% of total expenditures of all other non-financial industries to 48% in 1981. The figures in the table indicate the significant proportion of total capital expenditures by non-financial industries accounted for by the petroleum sector.

Table 3.5
TOTAL CAPITAL EXPENDITURES(1)
PETROLEUM AND NON-FINANCIAL INDUSTRIES

		Capital Expenditures	
		1980	1981
		($ millions)	
1.	Manufacturing(2)	8437	10224
2.	Mining(2)	2258	2465
3.	Other Non-financial(2)	6999	9419
4.	TOTAL NON-FINANCIAL (excluding petroleum)	17694	22108
5.	Petroleum	9820	10593
6.	TOTAL NON-FINANCIAL (including petroleum)	27514	32701
7.	Line 5 as a % of 6	35.7	32.4
8.	Line 5 as a % of 4	55.5	47.9

NOTES:

(1) SOURCE: Statistics Canada, 61-003, Industrial Corporations - Financial Statistics.

(2) Excludes the petroleum component of these industry sectors.

Dividends

Dividend payments by the industry totalled $1.1 billion in 1981, up 19%, as indicated in Table 3.6. Canadian controlled companies increased their dividend payments more (up 24%) than did foreign controlled companies (up 17%). Both groups of firms increased the percentage of net income paid out in the form of dividends, with Canadian controlled firms paying out 35% while the foreign controlled group paid out 36%.

Table 3.6
DIVIDEND PAYMENTS

	1980	1981	Change	Percentage of Net Income(1) 1980	1981
	($ millions)		(%)		
Integrated Companies	537	658	22.3	22.5	40.8
Senior Companies					
Canadian Controlled	256	318	24.3	18.8	35.1
Foreign Controlled	37	32	(15.5)	7.2	11.0
Junior Companies					
Canadian Controlled	65	78	20.4	22.3	36.1
Foreign Controlled	44	33	(24.3)	36.1	38.1
TOTAL INDUSTRY	940	1119	19.0	20.1	36.0
Canadian Controlled	321	396	23.5	19.5	35.3
Foreign Controlled	619	723	16.7	20.4	36.3

NOTE:

(1) The percentage of net income paid out is derived by dividing the dividend payments for each company group by their net income on total operations as reported in Table 1.3.

The increase in the percentage of after-tax profits paid out in the form of dividends was due to both the increase in the amount of dividends paid and the decline in net income on total operations. The decline in net income had a greater impact on the pay-out ratio than the absolute increase in dividends paid. If net income had remained constant, the percentage of net income paid out in the form of dividends for the industry would have risen to only 24%, rather than to 36%.

Net Working Capital

Table 3.7 shows that working capital, which is the difference between current assets and current liabilities, on a net basis for all companies, rose by 15% to $8.2 billion in 1981. The relatively large increase of more than $400 million in net working capital shown for Canadian controlled senior companies is primarily explained by the creation of a new company in this category in 1981.

Table 3.7
NET WORKING CAPITAL(1)

	1980	1981	Change
	($ millions)		(%)
Integrated Companies	5058	5405	6.9
Senior Companies			
Canadian Controlled	1146	1603	39.8
Foreign Controlled	619	775	25.2
Junior Companies			
Canadian Controlled	237	356	50.5
Foreign Controlled	59	49	(16.6)
TOTAL INDUSTRY	7119	8188	15.0
Canadian Controlled	1383	1958	41.6
Foreign Controlled	5737	6230	8.6

NOTE:

(1) Working capital is defined as current assets (inventory, cash and short-term investments, accounts receivable, and other current assets) less all current liabilities. The figures shown represent year-end balances of industry net working capital. The increase of $1069 million in working capital over the year can be related to Table 2.1 Sources of Funds and Table 3.1 Uses of Funds. Details of the components of working capital may be found in Schedule E of Appendix III.

The value of inventories (a major component of working capital) rose by $2.1 billion, or by 40%, to reach $7.4 billion. This increase was due to both domestic price increases and upward adjustments to inventory values reflecting changes in the PCC. Accounts receivable increased by 23% to $8.2 billion. Accounts payable increased from $5.7 billion to $7.1 billion during 1981, up 24%, while other current liabilities rose to $4.2 billion (up 36%).

All Other Uses of Funds

This item consists largely of funds used for acquisitions and takeovers by reporting companies, but also includes advances of funds, long-term notes receivable, and other long-term investments.

Table 3.8 shows that both foreign controlled and Canadian controlled companies increased their outlays on all other uses in 1981, although the rate of increase was substantially higher for Canadian controlled companies. Nearly 80% of the $6.3 billion spent during 1981 by Canadian controlled companies was for petroleum-related acquisitions of foreign controlled companies.

Table 3.8
ALL OTHER USES OF FUNDS

	1980	1981	Change	Percentage of Total 1980	Percentage of Total 1981
	($ millions)		(%)		
Canadian Controlled	1343	6278	367.4	82.6	94.8
Foreign Controlled	283	346	22.1	17.4	5.2
TOTAL INDUSTRY	1626	6624	307.2	100.0	100.0

The 1980 Monitoring Survey (pages 45-48) presented an analysis of the sources and uses of funds for a selected group (about 30) of large companies over the period 1971-80, and the relative performance of the Canadian controlled vis à vis the foreign controlled companies within the selected group. In view of the large number of takeovers in 1981, it is not feasible to assess the relative performance of these two groups of firms over the period 1971-81. Data are presented for the select group as a whole for the period 1971-81 in Schedule G of Appendix III in order to allow for an appreciation of the development of the industry through time. The salient point to be noted from these data is that 1981 saw declines in both net income and internal cash flow after a decade of steady annual growth.

IV. CASH FLOW AND FINANCING OF INVESTMENT

The first section of this chapter presents an analysis of internal cash flow for both Canadian controlled and foreign controlled companies and the various demands against that cash flow. The second section presents statistics on upstream and petroleum-related (upstream plus downstream) capital expenditures expressed as a proportion of internal cash flow. These statistics provide an indication of the extent to which internal cash flow is sufficient to finance the investment programs of the industry.

Analysis of Adjusted Cash Flow

Table 4.1 presents data on internal cash flow from total operations in both 1980 and 1981 for Canadian controlled and foreign controlled companies. The expensed portion of interest charges has been added back to internal cash flow and, therefore, the 'adjusted' cash flow figures in the table differ from the cash flow figures presented elsewhere in this report. Dividends, long-term debt repayment, increased inventory investment and interest charges (including capitalized interest) are subtracted from internal cash flow (as defined above) in order to derive the residual cash flow available for other purposes. The remaining or residual cash flow, after deductions requiring cash outlays have been accounted for, indicates that amount of financial resources generated by operations which is available for capital expenditures or for other uses.

As shown, the amount of residual cash flow available to Canadian controlled and foreign controlled firms declined by 39 and 36% respectively in 1981. In 1980 and 1981, Canadian controlled companies had 48 and 27% respectively of their total internal cash flow available for investments other than those listed in the table. The comparable ratios for foreign controlled companies were 67% in 1980 and 49% in 1981. These figures indicate that the petroleum industry as a whole in 1981 had a considerably lower proportion of its internal cash flow available for capital expenditures and other uses than it did in 1980, after providing for certain major expenditures which require cash outlays during the year.

Cash Flow and Investment

Table 4.2 shows that upstream capital expenditures for the overall industry represented 130% of upstream internal cash flow in 1981, up from 103%. These figures show that for each dollar of internal cash flow generated by upstream operations in 1981, the industry invested $1.30 in upstream capital expenditures.

The increase in the upstream investment ratio to 130% is explained by the fact that upstream capital expenditures in Canada declined less slowly, down 3% (Table 3.2), than did upstream internal cash flow, down 23% (Table 2.2). If upstream internal cash flow had remained constant, the upstream investment ratio in 1981 would have been 100% (assuming no change in capital expenditures as a result of the modified cash flow figure). The upstream investment ratio for Canadian controlled firms (169%) exceeded that for foreign controlled companies (106%).

Table 4.1
ANALYSIS OF ADJUSTED CASH FLOW(1)
FROM TOTAL OPERATIONS

	Canadian Controlled			Foreign Controlled		
	1980	1981	Change	1980	1981	Change
	($ millions)		(%)	($ millions)		(%)
1. Adjusted Cash Flow(1)	4082	4402	7.8	6288	5429	(13.7)
2. less Interest Charges(2)	733	1676	128.6	243	392	61.3
3. Dividends	321	397	23.5	619	723	16.7
4. Inventory Investment(3)	701	560	(20.1)	998	1553	55.6
5. Decrease in Long-term debt	380	580	52.8	231	81	(65.1)
6. Residual Cash Flow	1947	1189	(38.9)	4197	2680	(36.1)
7. Line 6 as % of Line 1	47.7	27.0	-	66.7	49.4	-

NOTES:

(1) Internal cash flow has been adjusted by adding back the expensed portion of interest charges. The 1981 internal cash flow figures shown in this table are equivalent to those presented in Table 2.3.

(2) Includes both interest charges expensed to operations and capitalized.

(3) The figures represent the year-over-year change in inventory investment.

Table 4.2
CAPITAL EXPENDITURES
AS A PERCENTAGE OF INTERNAL CASH FLOW

	Upstream(1)		Petroleum related(2)	
	1980	1981	1980	1981
	(%)			
Integrated	79	105	63	91
Senior Companies				
Canadian Controlled	116	155	100	150
Foreign Controlled	92	84	91	84
Junior Companies				
Canadian Controlled	190	229	195	277
Foreign Controlled	202	227	202	223
TOTAL INDUSTRY	103	130	88	120
Canadian Controlled	129	169	114	169
Foreign Controlled	90	106	75	95

NOTES:

(1) Upstream capital expenditures in Canada as a percentage of cash flow generated from upstream operations.

(2) Petroleum-related (defined as upstream plus downstream) capital expenditures in Canada as a percentage of cash flow from petroleum-related activities.

Petroleum-related (upstream plus downstream) capital expenditures as a percentage of internal cash flow of petroleum-related operations for the overall industry rose from 88 to 120%. The increase in this ratio was due to a combination of a growth of more than 150% in downstream capital expenditures (Table 3.2), largely by the foreign controlled integrated companies, and a decline in cash flow from petroleum-related operations.

Although not long-term in nature, investments in inventory are comparable, in some ways, to capital expenditures. Both classes of expenditure represent outlays for assets, with a view to generating future revenue flows. Funds for purchases of both capital assets and inventories must be drawn from either internal or external cash flows. To the extent that internal cash flows are insufficient to cover these purchases (and other cash requirements), funds from other sources (such as new debt or equity issues) are required.

Table 4.3 presents data on internal cash flow from total operations compared to total capital expenditures with and without an allowance for inventory changes.(1) The table indicates that internal cash flow from all operations exceeded capital expenditures (inventory change excluded) for both the integrated companies as well as for the foreign senior companies. Results for the foreign controlled junior companies, however, compare more closely to those for the Canadian controlled companies. Capital expenditures for these latter groups varied from nearly double to almost 250% of their respective internal cash flows.

The impact of including inventory investments with capital expenditures is most apparent for the integrated group, where the investment ratio increased from 99 to 138%. Only the foreign senior companies had internal cash flows exceeding the sum of their capital expenditures and inventory changes. For the other three groups, the sum of capital expenditures and increase in inventories varied from about double to two and a half times their funds from operations.

Taking all foreign controlled companies as a group, the addition of higher inventory investment to total capital expenditures resulted in total outlays that were 33% above funds generated from total operations. In contrast, capital expenditures for Canadian controlled firms were more than double their internal cash flows, with increased inventory investments adding another 19 percentage points to the ratio.

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(1) In order to produce data on inventories that are comparable or analogous to capital expenditures, allowance must be made for the fact that inventories are continuously acquired and sold during the reporting period. Inventory investment is the net increase in inventory stock levels from the beginning to the end of the period.

Table 4.3
CAPITAL EXPENDITURES AND INVENTORY INVESTMENT(1)
IN 1981 AS A PERCENTAGE OF INTERNAL CASH FLOW

	Inventory Change Excluded	Inventory Change Included(2)
	(%)	
Integrated	99	138
Senior Companies		
Canadian Controlled	197	219
Foreign Controlled	87	94
Junior Companies		
Canadian Controlled	249	258
Foreign Controlled	193	195
TOTAL INDUSTRY	143	169
Canadian Controlled	211	230
Foreign Controlled	102	133

NOTES:

(1) Inventory values are reported to the PMA on a total company basis only. Therefore, the figures shown compare total capital expenditures including inventories with the internal cash flow from total operations of reporting companies.

(2) Capital expenditures have been adjusted to include the change in the value of inventories over the year.

V. TAXES, ROYALTIES AND REVENUE SHARES

This chapter presents estimates of the revenue shares to industry and governments arising from the production of petroleum in 1980 and 1981. The estimates presented here differ from those indicated in the 1980 Monitoring Survey for two reasons. First, the revenue shares are calculated using the methodology used by the federal government and the governments of the producing provinces in the Energy Pricing and Taxation Agreements (EPTA) signed in the fall of 1981.(1) The PMA decided to use this methodology in order to facilitate comparison with the revenue sharing estimates presented in those agreements.

The second difference is due to the fact that estimates of revenue shares in previous Monitoring Surveys related primarily to upstream revenues and were based on data for PMA companies only. In contrast, the scope of the above mentioned EPTA documents included various downstream charges such as the Petroleum Compensation Charge(2) and provided estimates of revenue shares for all companies in the petroleum industry. Some of the revenue sharing components presented in this chapter (PGRT, cash flow, operating costs, corporate income tax and PIP grants) are based on data provided by PMA reporting companies, and have been grossed up by appropriate amounts in order to provide total industry estimates. Therefore, values presented in this chapter for these revenue sharing components will not equal those shown elsewhere in this report for PMA companies only.

Some of the measures agreed to in the EPTA (e.g. the Incremental Oil Revenue Tax) did not take effect in 1981, and those measures are not considered here. Some other taxes, such as the Oil Export Charge, are imposed after the product has been sold, so that data on the amount of the charge are not included in the financial records of PMA reporting companies. The PMA has obtained aggregate data on such items from outside sources such as provincial governments and Revenue Canada.

Table 5.1 presents an estimate of revenue shares, in both absolute and percentage terms, for 1980 and 1981. For 1981, the percentage distribution is estimated to be: industry 50.4%, provincial 30.4% and federal 19.2%. The estimated decreases of 4.5 and 4.0 percentage points in the provincial and industry share respectively from 1980 to 1981 were offset by a 8.5 percentage point increase in the federal share.

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(1) Estimates of revenue shares between the federal government and Alberta, Saskatchewan and British Columbia are found on pages 33, 10 and 5 respectively of the energy agreements between these governments.

(2) The glossary contains descriptions of each of the taxes referred to in this chapter.

Table 5.1
REVENUE SHARING ESTIMATES

	REVENUES		RELATIVE SHARES	
	1980	1981	1980	1981
	($ millions)		(%)	
Industry				
Upstream Internal Cash Flow	7741	5887		
Operating Costs	2964	3260		
Petroleum Incentives Payments (PIP)	-	810		
Land Payments	(1446)	(825)		
TOTAL INDUSTRY	9259	9132	54.4	50.4
Provincial				
Royalties and Freehold Tax(1)	4340	4425		
Oil Export Charge(2)	60	359		
Corporate Income Tax(3)	117	208		
Land Payments	1435	815		
Petroleum Incentives Payments (PIP)	-	(296)		
TOTAL PROVINCIAL	5952	5511	34.9	30.4
Federal				
Natural Gas and Gas Liquids Tax (NGGLT)	90	834		
Oil Export Charge(2)	730	359		
Petroleum and Gas Revenue Tax (PGRT)	-	1063		
Petroleum Incentives Payments (PIP)	-	(514)		
Corporate Income Tax	996	1301		
Canadianization Ownership Tax	-	551		
Net Petroleum Compensation Charge(4)	-	(132)		
Land Payments	9	10		
TOTAL FEDERAL	1825	3472	10.7	19.2
GRAND TOTAL	17036	18115	100.0	100.0

NOTES:

(1) Data on royalties were obtained from provincial sources. Royalties are net of provincial drilling and geophysical incentives, new oil and gas royalty holidays and enhanced recovery royalty relief. Indian royalties and royalties paid to freeholders are excluded.

(2) The NEP announced that revenues from the charge on exports of heavy oil would be shared equally with the producing provinces, effective November 1, 1980. Authority to effect this sharing is included in Bill C-103, An Act to amend the Petroleum Administration Act and to enact provisions related thereto.

(3) The provincial share of corporate income taxes is net of rebates received by industry from provincial governments.

(4) Net PCC is the revenue accruing to the Government of Canada less the amounts required to finance oil import compensation and any oil production qualifying for the New Oil Reference Price. The federal government incurred a deficit of $3.0 billion on the PCC in 1980--not shown in the table.

According to the revenue sharing framework of the EPTA documents, operating costs are considered to be a part of industry's share of total revenues. The addition of operating costs to the industry share represents a considerable change from the methodology used in the 1980 Monitoring Survey (p.32) where such costs were excluded from the net industry share. If operating costs are excluded from the industry share in Table 5.1, the relative shares in 1981 are: industry 39.5%, provincial 37.1% and federal 23.4%. On this basis, the 1980 percentages are 44.7%, 42.3% and 13.0% respectively.

The federal government, in its publication 1982 NEP Update, presented estimates of revenue shares with the industry portion computed as net of operating costs. The revenue sharing estimates for the year 1981 in the NEP update were: industry 41%, provincial 36% and federal 23%. These figures compare closely to the PMA estimates if operating costs are excluded from the industry share.

Industry Share

As shown in Table 5.1, the petroleum industry's share of revenues declined from $9.3 billion to $9.1 billion to account for 50.4% of total revenues available for sharing in 1981. Internal cash flow on upstream operations for the total industry(1) declined by more than $1.8 billion to $5.9 billion. Operating costs (excluding interest charges but including allocated overhead expenses) rose by about 10% to $3.3 billion.

Accrued PIP grants to the overall industry are estimated at $810 million in 1981, and this amount is included as part of the industry share. As shown in the table, the estimated total of $810 million of PIP grants accruing to the overall industry is distributed between the federal and Alberta governments in the amounts of $514 million and $296 million respectively. Land payments to governments, primarily provincial, are subtracted in order to derive the net industry share.

Provincial Share

The provincial share of revenues declined by more than $400 million to $5.5 billion, or to 30.4% of total revenues available for sharing. The major reason for this decrease was a drop of more than $600 million in land and lease payments to the provinces. Of the $815 million total provincial land payments in 1981, Alberta received $677 million compared to $88 million for British Columbia, $41 million for Saskatchewan and

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(1) PMA reporting companies accounted for 86.6% of total industry upstream production revenues in 1981 (see Appendix II). Comparable data for 1980 are not available, but the same ratio has been assumed for that year. Therefore, the internal cash flow estimates for the total industry (exclusive of drilling funds) have been derived by grossing up the PMA upstream cash flow (Table 2.2) by a factor of 1.15 (i.e. the reciprocal of 0.866).

$10 million for other provinces. Payments of PIP grants by the Alberta government in 1981, which are estimated at $296 million, also contributed to the reduction in the provincial share of revenues.(1).

Royalties and freehold taxes continued to provide the largest portion of the provincial share, rising slightly to $4.4 billion in 1981. Of this amount, about $3.9 billion accrued to Alberta, $214 million (including estimated deemed royalties on natural gas production) accrued to British Columbia and Saskatchewan received $297 million.

Sharing of the export charge on heavy crude oil exports with the federal government yielded an estimated $359 million to the provinces in 1981. Of this amount, it is estimated that $250 million and $109 million accrued to Saskatchewan and Alberta respectively. The reason for the relatively low provincial share of the oil export charge in 1980 ($60 million compared to the federal share of $730 million) is that sharing did not commence until November 1, 1980.

Provincial corporate income tax collections (net of rebates provided by provincial governments to the industry) increased to $208 million.(2) A breakdown of provincial current income taxes by province is not available.

Federal Share

The largest shift in revenues, both in absolute and relative terms, occurred in the federal component which rose to $3.5 billion and accounted for 19.2% of the total revenues available for sharing in 1981.

Most of the increase in the federal share was accounted for by two new taxes announced in the NEP. The Natural Gas and Gas Liquids Tax (NGGLT), which is a tax on the consumption of natural gas and natural gas liquids, amounted to $834 million in 1981. The relatively low figure of $90 million shown for the NGGLT in 1980 is due to the fact that this tax became effective on November 1, 1980. The PGRT also made

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(1) As part of the EPTA, the Government of Alberta announced that it would be providing individual 'Canadianization grants' to encourage additional Canadian participation in oil sands development (page 15, EPTA). These grants, which are additional to PIP, are to be given to companies lacking sufficient taxable income for purposes of claiming normal corporate tax deductions and in the aggregate are not to exceed $600 million. No funds in the form of these grants were paid out in 1981.

(2) Estimates of total industry current income taxes were derived by grossing up the current income tax data for PMA reporting companies by a factor of one-half that used for the cash flow calculations. The reason for the smaller gross up factor used for corporate taxes is that the smaller companies not reporting to the PMA are estimated to pay a lower percentage of current taxes than the average for PMA companies.

an important contribution to the federal share and is estimated at $1063 million for the total industry in 1981.(1)

Corporate tax payments to the federal government on upstream activities by the overall industry are estimated at $1.3 billion in 1981, an increase of more than $300 million.

The Canadian Ownership Tax accounted for $551 million of the federal share of revenues in 1981. This tax, which was levied on crude oil and natural gas consumed in Canada, is intended to generate revenues for the federal government for the purpose of acquiring ownership interests in non-resident owned Canadian oil and gas operations.

One condition of the EPTA with the Alberta government was that the federal government not run a surplus on the Petroleum Compensation Charge (PCC) over the period of the agreement, 1981 to 1986. The federal deficit of $132 million in 1981 is a net figure reflecting more than $4.2 billion in collections by the federal government and nearly $4.4 billion in payments to the industry.(2) The federal government's deficit on the PCC in 1980 was $3.0 billion.

The reason for the relatively large deficit in 1980 as compared to 1981, is that payments to the industry in the former year were made largely from the general revenues (consolidated revenue fund) of the federal government. However, in 1981 the deficit was virtually eliminated due to increases in the PCC levy (see Appendix V) in line with the self-financing objective of the compensation program.

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(1) The PGRT figure of $924 million for PMA companies was grossed up to the industry estimate of $1063 million on the basis of the estimate of total industry upstream production revenues.

(2) Of the $4.2 billion in collections, $3.7 billion was accounted for by regular PCC levies while $0.5 billion was accounted for by the special compensation levies imposed as a result of the Alberta production cutbacks in March and June of 1981. On the payments side, $3.7 billion was paid to Canadian importers and refiners of imported crude oil and $0.7 billion was paid to producers of synthetic oil for total outlays of more than $4.3 billion.

VI. RESEARCH AND DEVELOPMENT ACTIVITIES

Data on research and development (R&D) activities are compiled from Statistics Canada questionnaires (submitted by PMA survey companies) which that Agency makes available to the PMA by means of an agreement under the Statistics Act.(1) The definition of R&D activities used by Statistics Canada and the PMA is consistent with that employed by Revenue Canada for taxation purposes. This definition of R&D excludes items such as prospecting and exploratory drilling, the development of oil and gas wells, and pilot/demonstration plants to develop a commercial technology. A total of 40 PMA companies, mostly larger firms, reported R&D expenditures in 1981, as compared to 37 companies in 1980.

A breakdown of R&D activities by the five company groups used in this report cannot be provided without revealing confidential information. It is, however, possible to report a breakdown for most items between the integrated companies, other foreign controlled companies, and all Canadian controlled companies.

Two types of R&D expenditures are considered in this chapter: intramural and extramural. Intramural R&D is that conducted by a reporting company using its own laboratories, equipment and personnel, either for its own purposes, or for another firm under contract. Extramural R&D is that conducted (usually under contract) for a reporting company by another company, organization or individual.

Intramural Expenditures

PMA reporting companies spent $332 million on intramural energy R&D in 1981, an increase of 64%, as shown in Table 6.1.(2) The most significant increase occurred in the conventional oil and gas area (see Appendix IV for definition) where outlays increased from $63 million to $157 million in 1981. The $157 million figure includes $39 million of refinery-related expenditures in 1981 (expenditures related to refineries were included in the conventional oil and gas category in the 1980 Monitoring Survey). These combined expenditures accounted for 47% of total disbursements (conventional oil and gas 35%, refining 12%) compared to 31% in 1980. Disbursements for in-situ production technology increased by 33% to $122 million.

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(1) The questionnaires being made available to the PMA are:
   (a) Research and Development in Canadian Industry, and
   (b) Energy R&D Expenditures by Area of Technology.

(2) Final data on intramural R&D expenditures in 1981 by all sectors of Canadian industry are not yet available. Statistics Canada catalogue 13-003 (volume 5, number 8) contains data on intended R&D expenditures in 1981. On this basis, intramural R&D expenditures by all sectors of Canadian industry were projected to total $1752 million in 1981. The petroleum and natural gas industry accounted for $370 million, or about 21%, of these total intended expenditures.

Table 6.1
INTRAMURAL ENERGY R&D EXPENDITURES BY AREA OF TECHNOLOGY(1)

		1980 ($ millions)	1981 ($ millions)	Change (%)	Percentage of Total 1980	Percentage of Total 1981
1.	Renewable Resources	2	1	(50)	1	0
2.	Transportation and Transmission	2	0	(100)	1	0
3.	Conservation	5	6	20	2	2
4.	Fossil Fuels					
	(a) Oil and Gas	63(2)	118	87	31	35
	(b) Refining	n/a(2)	39	-	-	12
	(c) Oil Sands and Heavy Oil					
	(i) Exploration, Surface Mining and Production(3)	31	37	26	15	11
	(ii) In-situ Production	92	122	33	45	37
	(d) Coal	8	9	13	4	3
5.	TOTAL(4)	203	332	64	100	100

NOTES:

(1) Appendix IV provides definitions for the various areas of technology shown in the table.

(2) Intramural expenditures for refinery and petroleum products R&D in 1980 were included under oil and gas.

(3) Excludes expenditures by Syncrude Canada Ltd. that are included in the extramural component (Table 6.2). A small amount of uranium mining expenditures is included in category 4(c)(i) in the table. Separate data are not presented because of disclosure considerations.

(4) In addition to the figures shown, reporting companies spent $4 million and $14 million on non-energy related R&D activities in 1980 and in 1981 respectively.

In addition to the $332 million of intramural energy R&D expenditures in 1981, reporting companies spent $14 million in non-energy areas for total intramural outlays of $346 million. The integrated companies (all foreign controlled) accounted for 62% of total intramural R&D expenditures. Other foreign controlled companies and Canadian controlled firms accounted for 10 and 28% respectively of the total intramural expenditures.

Of the $346 million used to finance intramural expenditures, $273 million, or 79%, was generated internally by reporting companies. The second most important source of funds was $27 million supplied by parent, affiliated or subsidiary companies--most of which were located outside Canada. Federal and provincial governments through grants provided $14 million of the funds spent intramurally by reporting companies in 1981.

The largest proportions of total intramural R&D expenditures (energy and non-energy) in Canada were carried out in Alberta ($229 million) and Ontario ($61 million), which accounted for 66 and 18% respectively of total outlays in 1981. The Alberta share did not change since 1980, while the Ontario share decreased by 2 percentage points.

Extramural Expenditures

Extramural R&D expenditures, both energy and non-energy related, by PMA reporting companies totalled $117 million (up 80%), as shown in Table 6.2. Of the payments made for extramural R&D, a total of $66 million was paid to companies and institutions in Canada, while an amount of $51 million was paid to recipients abroad. Within the $51 million spent abroad in 1981, energy-related expenditures accounted for about $36 million, of which $28 million was related to conventional fossil fuel technology. No breakdown between energy and non-energy related extramural outlays in Canada is available for either 1980 or 1981.

Table 6.2
EXTRAMURAL R&D PAYMENTS
TO RECIPIENTS IN CANADA AND ABROAD

RECIPIENT	IN CANADA		ABROAD		TOTAL	
	1980	1981	1980	1981	1980	1981
	($ millions)					
Parent and Affiliated Companies	0	n/a(1)	40	49	40	49
Other Corporations	22	63	0	2	22	65
Research Institutions and Other	4	3	0	0	4	3
TOTALS	26	66	40	51	66	117

NOTE:

(1) Data not available due to disclosure considerations.

In 1981, a total of $4 million was paid by reporting companies for patents, licences and technical 'know-how' derived from R&D performed in the past. Of that amount, 96% was received by technology sellers in foreign countries. In 1981, about $1 million was paid to reporting companies for technological rights owned by them.

VII. OWNERSHIP AND CONTROL TRENDS

This chapter begins by presenting estimates of the extent of foreign ownership and control of the oil and gas industry in 1981. The data used for the analysis were obtained by the PMA (with the consent of reporting companies) from Balance of Payments (BOP) questionnaires collected by Statistics Canada. The second section of this chapter examines the differences in financial structure between Canadian controlled and foreign controlled companies by presenting data on the ownership of capital employed in the Canadian petroleum industry.

The Statistics Canada definition of control, which is used here, is based on whether Canadian or foreign shareholders have potential control over a company's overall operations. While control is generally based on 50% or more ownership of voting shares, it is possible for effective control to be exercised with a smaller ownership block. For purposes of ownership calculations, the percentage of revenues (or any other measurement base) reflected by the ownership of voting rights by non-residents is assigned to the foreign owned category. In the case of control, all of the revenues (or other base) of the controlled company are assigned to the appropriate control category. To illustrate, the integrated group of companies included in this report (all foreign controlled) have varying rates of Canadian ownership (up to 30%), yet 100% of their revenues are assigned to the foreign controlled sector.

In March 1982, the federal government began accepting, on a provisional basis, applications for certificates of Canadian ownership rate and control status (COR/CS). Most of these applications are for purposes of deriving benefits under the Petroleum Incentives Program (PIP). While the COR regulations in some cases produce a more detailed calculation of Canadian ownership than the methodology used in this chapter(1), results are available at this time only for a small number of companies within the reporting population.

Estimates of 1981 Ownership and Control

The year 1981 witnessed a considerable amount of takeover activity in the Canadian oil and gas industry. This takeover activity primarily involved the acquisition by Canadian controlled companies of foreign owned and controlled companies with assets in Canada, and affected the levels of both foreign ownership and control of the industry. Another area of activity concerned various mergers, which involved share exchanges but not cash, and some acquisitions of Canadian controlled firms by other Canadian controlled firms. Although not as large in

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(1) The COR/CS regulations require most applicants to provide data on ownership blocks to the level of one-half of one percent compared to the 5% threshold for BOP purposes. For certain smaller applicants for COR/CS, the regulations allow the applicant to be 'deemed' to be 100% Canadian owned, if it is Canadian controlled and has not less than 50% Canadian ownership.

scope or dollar value as the takeover activity, these mergers had an impact on the level of foreign ownership (but not control), depending upon the ownership levels of the participants.

Table 7.1 lists the most significant petroleum industry takeovers that took place in 1981. The $7.6 billion total purchase price shown exceeds the amount of $6.6 billion indicated previously for 'other uses of funds' (Table 3.1) because some of the acquiring companies shown in Table 7.1 were not PMA reporting companies in 1981.

Table 7.1
MAJOR PETROLEUM INDUSTRY TAKEOVERS IN 1981(1)

Company Acquired	Acquired by	Purchase Price ($ millions)
Petrofina Canada	Petro-Canada	1450
Candel Oil	Sulpetro	536
HBOG	Dome Petroleum	2000 (2)
Alamo Petroleum Ltd.	Fairweather Gas	213 (3)
Amax Petroleum Ltd.	Fairweather Gas	-
Uno-Tex	Husky Oil Ltd.	371
Union Texas of Canada	Drummond Petroleum	101
Aquitaine	CDC	1600 (4)
Total Eastcan (assets)	Ranchmens Resources	47
Merland Exploration	Turbo Resources	132
Consolidated Nat. Gas	Merland Explorations	62
Great Basins Petroleum	United Canso	164
Suncor Inc. (partial)	Ontario Energy Corp	650
Union Oil of Canada	Union Oil of California	130
Kissinger Petroleum	Ranger Oil	55
Quasar Petroleum Ltd.	Oakwood Petroleum Ltd.	43
TOTAL		7554

NOTES:

(1) As reported in the press and other published sources.

(2) The takeover of Hudson's Bay Oil and Gas Company (HBOG) was completed by Dome Petroleum in March of 1982. The total purchase price of HBOG was about $4.0 billion.

(3) The $213 million figure covers the acquisition of both Alamo Petroleum Ltd. and Amax Petroleum Ltd. by Fairweather Gas.

(4) The Canada Development Corporation (CDC) also purchased the Canadian assets of Texasgulf Inc. in January 1982 for $620 million. A new Canadian controlled company called Canterra was formed by combining the assets of Aquitaine and CDC oil and gas with the relatively small oil and gas properties of Texasgulf Inc.

As shown in Table 7.2, the estimated level of foreign ownership of the industry based on petroleum-related (upstream plus downstream) revenues, declined by 6.7 percentage points to 67.2% in 1981, while the level of foreign control declined by 6.5 percentage points to 74.8%. These decreases were such that the relative geographic distribution of foreign ownership and control between 'United States' and 'Other Foreign' did not change markedly in 1981. Of the estimated 6.7 percentage point decline in foreign ownership, 4.1 percentage points, or 61%, was accounted for by increased ownership by the Canadian public sector, both federal and provincial. The 6.5 percentage point decline in foreign control was distributed between a 3.9 and 2.6 percentage point rise in control by the Canadian public and private sectors respectively.

Table 7.2
OWNERSHIP AND CONTROL OF THE PETROLEUM INDUSTRY(1)

	Ownership		Control	
	1980	1981	1980	1981
	(%)		(%)	
United States	57.2	52.7	61.6	56.4
Other Foreign	16.7	14.5	19.7	18.4
TOTAL FOREIGN	73.9	67.2	81.3	74.8
Canadian Public Sector(2)	3.8	7.9	4.4	8.3
Canadian Private Sector	22.3	24.9	14.3	16.9
TOTAL CANADIAN	26.1	32.8	18.7	25.2

NOTES:

(1) Calculations are based on petroleum-related (upstream plus downstream) revenues. The figures are computed using ownership data as of the end of 1981. The estimated numerical effect of individual transactions on ownership and control levels can not be divulged due to confidentiality considerations.

(2) This includes federal and provincial Crown corporations as well as public sector interest in private sector companies.

The impact of the takeovers, considered alone, was to reduce the estimated level of foreign ownership and control by 4.1 and 5.7 percentage points respectively. This presentation of the estimated impact of the takeovers is somewhat less than that shown in the first

half 1981 Monitoring Survey(1) for two reasons. First, several of the takeovers listed in Table 7.1 were only partially completed in 1981, and just that partial impact is included in the calculations in this report. In contrast, the previous Monitoring Survey illustrated the impact of takeovers in the first half of 1981 as if the takeovers had been entirely completed at that time. The second, and more important, reason for the difference is that the calculations in this report show the estimated impact of the takeovers on petroleum-related revenues at the end of 1981, whereas the previous survey showed the impact on these revenues at the end of 1980.

Stock market transactions also had an impact on reducing levels of foreign ownership (but not control) in 1981. Purchases by Canadians of shares previously held by non-residents in both Canadian controlled and foreign controlled companies resulted in an estimated decline of 1.4 percentage points in the level of foreign ownership in 1981. Canadian controlled companies and most of the foreign controlled companies that had increases in Canadian ownership levels in 1981 had a growth rate in their petroleum-related revenues above the industry average. This, and other factors, accounted for the remaining 1.2 percentage point decline in foreign ownership.

Table 7.3 presents estimated levels of foreign ownership and control based on petroleum-related revenues for various company groups, and also for other measurement bases including various revenues, exploration expenditures, and total assets. Foreign ownership of upstream revenues declined by an estimated 9.0 percentage points to 63.0% in 1981, while the level of foreign control dropped about 13 points to 64.4%.(2) Of these declines, a total of 5.5 and 9.7 percentage points respectively were due to takeover activity which, with few exceptions, were concentrated in the upstream sector.

The federal government's NEP Update of May 1982 (page 46) estimated foreign ownership and control of upstream revenues (the basis used for measuring progress towards the NEP's Canadianization objectives) to be 65.3 and 66.9% respectively, or about 2 percentage points higher than the PMA estimates in Table 7.3. The estimates contained in the Update are higher than those of the PMA primarily because the Update figures are based on upstream revenues at the end of 1980.

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(1) The first half 1981 Monitoring Survey (page 31) indicated that the impact of the takeovers in the first six months of that year was to reduce the level of 1980 foreign ownership and control by 4.5 and 7.2 percentage points respectively.

(2) The reason that estimated foreign control declined more (down 13 points) than foreign ownership is that, in the event of a change in control status, all of the revenues of the company in question are transferred to the new control classification.

The relative predominance of Canadian controlled firms in natural gas production as compared to oil production is reflected by the estimated 59.7% level of foreign ownership of natural gas revenues in 1981 compared to 65.6% for crude oil revenues. The table also indicates that the level of foreign ownership and control of exploration expenditures declined substantially in 1981, down 11.4 and 12.3 percentage points respectively.

Table 7.3
FOREIGN OWNERSHIP AND CONTROL
BY COMPANY GROUP AND CATEGORY

	Foreign Ownership		Foreign Control	
	1980	1981	1980	1981
	(%)		(%)	
PETROLEUM-RELATED REVENUES				
Integrated Companies	82.3	79.4	100.0	100.0
Senior Companies(1)	59.2	43.7	47.8	25.6
Junior Companies(1)	56.0	47.9	48.4	39.4
TOTAL INDUSTRY	73.9	67.2	81.3	74.8
TOTAL ASSETS				
Integrated Companies	82.2	78.4	100.0	100.0
Senior Companies(1)	50.3	40.3	32.2	15.1
Junior Companies(1)	46.9	38.7	33.1	25.1
TOTAL INDUSTRY	62.1	52.6	58.5	45.0
OTHER MEASUREMENT BASES				
Upstream Revenues	72.0	63.0	77.3	64.4
Natural Gas Revenues(2)	n/a	59.7	n/a	57.8
Crude Oil Revenues(2)	n/a	65.6	n/a	68.8
Downstream Revenues	75.3	69.5	84.1	80.6
Exploration Expenditures	66.8	55.4	64.4	52.1

NOTES:

(1) These categories comprise both Canadian controlled and foreign controlled companies.

(2) In 1981, the PMA began collecting individual company data on the natural gas and crude oil components of upstream revenues. Therefore, ownership and control estimates measured on the basis of these revenues are not available for 1980.

As noted in the 1980 Monitoring Survey (page 40), the level of both foreign ownership and control of the petroleum industry in Canada has dropped substantially since 1975. Much of the decline prior to 1981 resulted from the growth of the public sector with the formation of companies such as Petro-Canada, Alberta Energy Company, Saskatchewan Oil and Gas Corporation, and CDC Oil and Gas Limited. Table 7.4 indicates the dramatic decreases in foreign ownership and control which occurred in 1981 compared to the slower declines over the preceeding ten years.

Table 7.4
FOREIGN OWNERSHIP AND CONTROL
OF THE PETROLEUM INDUSTRY

	1971(1)	1975(1)	1977(1)	1980	1981
			(%)		
PETROLEUM-RELATED REVENUES					
Foreign Ownership	79.5	76.1	73.7	73.9	67.2
Foreign Control	94.4	92.9	87.0	81.3	74.8
TOTAL ASSETS					
Foreign Ownership	77.7	72.2	66.8	62.1	52.6
Foreign Control	89.6	84.7	73.3	58.5	45.0

NOTE:

(1) Estimates for the years 1971, 1975 and 1977 are taken from the 1979 Monitoring Survey (page 26), and are computed using CALURA ownership statistics. Also, the estimates for the earlier years are based on a slightly smaller population than those for the years 1980 and 1981.

The 1980 Monitoring Survey noted that there is no one correct measure of the level of foreign ownership and control, and contained a discussion (pages 39-43) of the limitations of using assets as a measurement base. A major weakness of using assets as a measurement base for estimates of ownership and control levels is that, for financial reporting purposes, companies indicate the value of their assets at historic 'book value', or the price at which the assets were originally purchased. The book value of assets can be significantly below current market value. In the event of takeover activity, the acquired assets are shown at the new (and higher) market value in the financial records of the acquiring company.

The assets associated with the main takeovers that took place in 1981 had an estimated market value of over $7.6 billion (Table 7.1), but a historical book value of only $1.3 billion. Therefore, using assets as a measurement methodology, one would add $7.6 billion to the valuation of the Canadian controlled sector in 1981 but subtract only $1.3 billion from the foreign controlled sector. In contrast, using petroleum-related revenues as the basis of measurement, the equivalent amount of revenue is transferred from one sector to another to take account of takeover activity. As shown in Tables 7.3 and 7.4, the estimated levels of foreign ownership and control of the industry in 1981 measured using assets as a base, were 52.6 and 45.0% respectively, well below the estimated levels based on petroleum-related revenues.

The estimates of foreign control of the oil and gas industry in Canada presented here differ from those published by Statistics Canada, whose most recently published figures (measured on capital employed)(1) indicate a projected level of 55% foreign control of the petroleum sector in 1978. This is well below the PMA estimate of 74.8% based on petroleum-related revenues for 1981 (Table 7.3). The main reason for this difference is the use of capital employed as a measurement base.

Another, although less significant, reason for the lower level of foreign control indicated by the Statistics Canada figures is the fact that its reporting universe is considerably wider than that of the PMA. In addition to the PMA companies, the Statistics Canada universe includes pipeline companies, service companies incidental to the petroleum industry, petrochemical companies and marketing operations including fuel distributors, etc. Most of those companies not included in the PMA survey, in particular those in the pipeline sector, are largely Canadian owned and controlled. As noted in the 1980 Monitoring Survey (page 43), if pipelines had been excluded from the figures, the Statistics Canada projected estimate of foreign control in 1978 based on capital employed would have been 66% as opposed to the 55% estimate that was published.

Ownership and Control of Capital Employed

Table 7.5 illustrates the differences in financial structure between Canadian controlled and foreign controlled companies by presenting the components of ownership and control of capital employed (shareholders' equity plus long-term debt) for PMA reporting companies at the end of 1980, the most recent data available. The figures indicate that Canadians owned 48% of the capital employed ($15.8 billion of $33.1 billion) in the Canadian petroleum industry at the end of 1980. However, Canadians owned only 30% of the total equity ($5.7 billion of

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(1) Capital employed is defined as shareholders' equity plus long-term debt. This definition is derived from data provided in Statistics Canada catalogue 67-202 annual. This is a different definition from that of total assets less current liabilities (which most petroleum companies use when publishing capital employed data), which is used in Table 1.5 of this report. The difference between the two definitions is deferred taxes, which are included in the latter definition but not in the former.

Table 7.5
CAPITAL EMPLOYED IN CANADA
BY PMA REPORTING COMPANIES(1)

CONTROL STRUCTURE	OWNERSHIP STRUCTURE (END OF 1980)			
	Canadians	United States Residents	Other Non-residents	Total
		($ billions)		
Canadian Controlled				
Equity(2)	3.3	1.1	0.1	4.5
Preferred Stock	3.0	0.2	-	3.2
Long-term Debt(3)	5.1	0.6	0.5	6.2
Capital Employed	11.4	1.9	0.6	13.9
U.S. Controlled				
Equity(2)	1.7	10.2	0.1	12.0
Preferred Stock	0.1	0.5	-	0.6
Long-term Debt	1.0	1.3	-	2.3
Capital Employed	2.8	12.0	0.1	14.9
Other Foreign Controlled				
Equity(2)	0.7	(0.1)	2.1	2.7
Preferred Stock	0.3	-	0.1	0.4
Long-term Debt	0.6	0.5	0.1	1.2
Capital Employed	1.6	0.4	2.3	4.3
TOTAL				
Equity(2)	5.7	11.2	2.3	19.2
Preferred Stock	3.4	0.7	0.1	4.2
Long-term Debt	6.7	2.4	0.6	9.7
Capital Employed	15.8	14.3	3.0	33.1

NOTES:

(1) Data were obtained from company Balance of Payments (BOP) questionnaires submitted to Statistics Canada. The figures in the table represent capital employed in Canada only, and exclude deferred income taxes. Capital employed related to operations abroad are excluded.

(2) Equity here excludes preferred stock as the latter generally does not participate in the earnings of the corporation and is more of a leverage instrument like long-term debt.

(3) Long-term debt includes $246 million of minority shareholders' interest. A negligible amount ($14 million) of minority shareholders' interest is included in the long-term debt for U.S. controlled and other foreign controlled companies.

$19.2 billion), but nearly 70% of the total long-term debt ($6.7 billion of $9.7 billion).

Therefore, although Canadians 'owned' 48% of the total capital employed of the petroleum industry in Canada, they only participated in 30% of industry earnings (i.e. their share of total equity) and controlled 23% of these earnings ($4.5 billion of $19.2 billion). In contrast, non-residents (U.S. and other) owned 52% of the capital employed in the Canadian petroleum industry, but participated in 70%, and controlled 77%, respectively, of industry earnings in 1980.

The debt to equity ratio (long-term debt less minority shareholders' interest plus preferred stock all divided by equity plus minority shareholders' interest) for Canadian controlled companies equalled 2.0 to 1 (the sum of $6.0 billion and $3.2 billion divided by $4.7 billion). In contrast, U.S. and other foreign controlled companies had debt to equity ratios of only 0.2 to 1 and 0.6 to 1 respectively, well below that for Canadian controlled companies.

Canadian controlled companies generally employ the full cost accounting method, while foreign controlled companies employ the successful efforts method. This produces a lack of comparability of the retained earnings figures, with a tendency to make retained earnings of Canadian controlled companies larger.

Table 7.6 summarizes the equity and debt portions of the ownership of total capital employed by the three groups of companies in Table 7.5. The estimated 30% Canadian ownership of total equity compares closely with the estimate of 26% Canadian ownership of the petroleum-related revenues of the industry in Canada in 1980 (Table 7.3).

Table 7.6
SUMMARY OF OWNERSHIP STRUCTURE

	TYPE OF OWNERSHIP	
	Canadian	Foreign
	(%)	
Canadian Controlled		
Equity	73	27
Preferred and Debt	86	14
U.S. Controlled		
Equity	14	86
Preferred and Debt	38	62
Other Foreign Controlled		
Equity	26	74
Preferred and Debt	56	44
TOTAL INDUSTRY		
Equity	30	70
Preferred and Debt	73	27

As a result of takeover activity in 1981, and the associated changes in debt and equity structure, it may be anticipated that both the ownership and control of capital employed in the petroleum industry in Canada have changed considerably since the end of 1980. The next Monitoring Survey, which will report on the first six months of 1982, will present data on capital employed in Canada by PMA reporting companies as of year end 1981.

VIII. INTERNATIONAL FLOWS OF FUNDS

This chapter presents statistics on the international flows of funds of companies reporting to the PMA.(1) The flow of funds is conventionally separated into current and capital accounts. Current account items include dividends, interest payments (on both short-term and long-term debt) and business service payments such as rental payments, management fees and payments for technology.

The capital account is divided into short-term flows (inter-company accounts, short-term borrowings and bank loans) and long-term flows. Long-term capital flows are subdivided into direct investments(2), such as a parent company's investment in a foreign subsidiary or foreign affiliated company, and portfolio investments, which may be in the form of equity or debt.

Table 8.1 summarizes the international flows of funds related to the petroleum sector in 1980 and 1981. The figures shown in the table represent the net flows of funds as a result of international transactions related to long-term investments by the petroleum industry both in Canada and abroad. Statistical Schedule H, Appendix III shows separately the international flows related to long-term investments in Canada and abroad.

As shown, the major change in the international flows of funds in 1981 was an outflow in the capital account for foreign controlled companies of more than $4.8 billion, compared to an inflow of $280 million in this account in 1980. The $4.8 billion outflow in the capital account in 1981 is the net result of three separate flows: $5.6 billion of direct investment outflows (i.e. reduction in the level of foreign direct investment in Canada) as a result of takeover activity; an inflow of $840 million in increased portfolio investment (largely made up of borrowings on international money markets by foreign controlled companies); and, a $61 million outflow as a result of increased direct investment abroad (i.e. foreign controlled companies investing abroad).

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(1) Data on international flows of funds are obtained from Balance of Payments (BOP) questionnaires collected by Statistics Canada. Subject to the approval of the reporting companies, these questionnaires are made available to the PMA by means of an agreement under the Statistics Act. Data presented here do not include payments and receipts related to exports and imports of goods and transportation services.

(2) Direct investment is defined as that which, in addition to being made for an economic return, also has the purpose of having a managerial input. For the Canadian petroleum industry, direct investment is principally investments of foreign parent corporations in their Canadian subsidiaries. Portfolio investment is investment for the purpose of obtaining a return with no management voice in the operations. This is principally all foreign debt (except that owed to foreign parent corporations) plus foreign equity in Canadian controlled companies.

Table 8.1
INTERNATIONAL FLOWS OF FUNDS(1)
FOR REPORTING COMPANIES 1980 and 1981

	CURRENT ACCOUNT			CAPITAL ACCOUNT(3)	
	Interest	Dividends	Business Service Payments	Transactions	TOTAL
			($ millions)		
INTERNATIONAL TRANSACTIONS RELATED TO LONG-TERM INVESTMENTS IN 1980(2)					
Canadian Controlled	(5)	(10)	(5)	(57)	(77)
Foreign Controlled	(40)	(447)	(126)	280	(333)
NET INFLOWS (Outflows)	(45)	(457)	(131)	223	(410)
INTERNATIONAL TRANSACTIONS RELATED TO LONG-TERM INVESTMENTS IN 1981					
Canadian Controlled	(62)	(29)	(4)	542	447
Foreign Controlled	(19)	(499)	(197)	(4838)	(5553)
NET INFLOWS (Outflows)	(81)	(528)	(201)	(4296)	(5106)

NOTES:

(1) Excluded from this table are all exports and imports of goods, transportation services, short-term capital flows, and changes in retained earnings. In the case of investments in Canada, increases in retained earnings would have the effect of increasing Canada's indebtedness to foreigners, while decreases would have the opposite effect.

(2) Figures derived from 1980 Monitoring Survey (page 37).

(3) All capital account figures are net. For example, the $542 million inflow shown for Canadian controlled firms represents long-term borrowing abroad net of repayment. Also, the $4838 million outflow for foreign controlled firms represents outflows of direct investment and other flows offset by inflows resulting from increased direct foreign investment.

The amount of $4.8 billion reported above as a capital account outflow for the petroleum industry shows only a portion of the total international flows of funds for the corporate sector and the overall economy. In order to obtain a complete picture of the international flows of funds resulting from takeover activity, the flows to other sectors of the economy would also have to be considered.(1) For example, a Canadian corporation acquired a foreign owned oil and gas corporation in 1981, resulting in a capital outflow in the oil and gas sector. However, the Canadian corporation borrowed money abroad to pay the foreign owners of the acquired corporation. Since the Canadian purchaser is a non-petroleum corporation, the inflow of capital in the form of debt will not be shown in the petroleum sector in the international flows of funds as published by Statistics Canada, but in the sector in which the acquiring company is classified. Thus, the total effect of this transaction on the international flows of funds is not shown when the petroleum sector is considered in isolation.

Some indication of the nature and extent of offsetting inflows to the above mentioned capital account outflow in the petroleum sector is provided in Statistics Canada's most recently published data.(2) According to the Statistics Canada publication, new issues of Canadian securities registered capital inflows of $13.6 billion for 1981, and the chartered bank net foreign currency position with non-residents registered capital inflows of $17.9 billion. As noted earlier, however, it is not possible to indicate what portion of these inflows was directly related to the petroleum sector.

On the current account, there were small increases in 1981 in the net outflows for PMA reporting companies. The total current account outflows in 1981 were $810 million, of which interest payments comprised $81 million, dividend payments $528 million, and business service payments $201 million. Each of these amounts are net outflows (Statistical Schedule H provides details). For example, the $81 million net outflow of interest payments is made up of a $188 million outflow in the form of payments to non-residents for investments in Canada and an inflow of $107 million in the form of payments received by Canadian corporations from non-residents for Canadian investments abroad.

Statistical Schedule H shows that dividends and business service payments are, for the most part, between related companies (non-arms' length). For example, almost 80% of dividend payments and more than 50%

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(1) Precise estimates of the nature and magnitude of all the financial transactions associated with the takeovers (e.g. the running down of U.S. dollar balances by Canadian financial institutions) are not available. A comprehensive analysis of the balance of payments impact of the takeovers on the overall Canadian economy would require an exhaustive analysis of each transaction (related to the takeovers) undertaken by each member of the Canadian financial and banking community.

(2) Statistics Canada Fourth Quarter 1981 Quarterly Estimates of the Canadian Balance of International Payments Catalogue 67-001.

of business service payments abroad for reporting companies in 1981 were paid to foreign parent companies. Similarly, those foreign controlled companies investing abroad received virtually all of their business service receipts from their foreign subsidiaries.

In addition to the long-term flows shown in Table 8.1, flows of funds arising from short-term transactions (less than one year term) between Canada and other countries amounted to a net inflow of $289 million in 1981 (See Schedule H). Foreign controlled and Canadian controlled firms registered net inflows of $109 million and $180 million respectively. Almost 90% of the transactions of the Canadian controlled companies were inter-company (non-arms' length). Foreign controlled companies accounted for 53% of their net inflows in inter-company transactions. The remainder was generally the repayment of short-term bank loans and other borrowings abroad.

Certain Canadian subsidiaries of foreign multinationals have been lending capital on a 'short-term' basis to sister corporations abroad. Some of these short-term loans have been outstanding for at least two years and are more in the nature of a long-term instrument as apparently the loans are simply being renewed each year. Since short-term loans are included in the current assets of the Canadian subsidiary companies, working capital figures for these companies may be overstated. Similarly, long-term outflows will be understated to the extent of the 'short-term' loans.

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Appendix I

GLOSSARY

Acquisitions--the acquisition of companies or the purchase of assets from other petroleum companies. These outlays are included under the category 'All Other Uses of Funds' in monitoring reports.

Amortization--the depreciation, depletion or charge-off to expense of intangible and tangible assets over a period of time. In the extractive industries, the term is most frequently applied to mean either (1) the periodic charge-off to expense of the costs associated with non-producing mineral properties incurred prior to the time when they are developed and entered into production or (2) the systematic charge-off to expense of those costs of productive mineral properties (including tangible and intangible costs of prospecting, acquisition, exploration and development) that had been initially capitalized (or deferred) prior to the time the properties entered into production, and thereafter are charged off as minerals are produced.

Canada Lands--those areas of Canada not within provincial boundaries.

Capital Employed--the book value of total assets less current liabilities.

Capital Expenditures--investments in new facilities, both capitalized and charged directly to current operations (exploration, development and production), plus capitalized repair expenditures.

Current Income Tax--the portion of the provision for income taxes, both federal and provincial, payable in the reporting period.

Debt/Equity Ratio--the ratio of long-term liabilities (over one year) to shareholders' equity (share capital plus retained earnings). Depending upon the terms and conditions attached to them, preferred shares may be treated as either debt or equity.

Deferred Income Taxes--taxes accrued and reflected as an expense in the company's income statement, but not payable to the taxing authority in the financial reporting period. Income taxes are deferred, for example, when companies write off capital assets (using capital cost allowances) for income tax purposes at rates that exceed those employed in preparing their financial reports. The amount of tax deferred is equivalent to an interest-free long-term loan.

Depletion--the amount charged to expense in the company's financial statements in the period covered relating to depletable assets that have been capitalized. (This is not the earned depletion allowance calculated for income tax purposes.)

Depreciation--the amount charged to expense in the period covered relating to depreciable assets that have been capitalized. (This is not the amount of capital cost allowance that is used to compute depreciation for income tax purposes.)

Development Expenditures--these expenditures typically include: drilling costs in an area of already proven oil or natural gas reserves, expenditures on field gathering systems, and the cost of acquiring proven reserves.

Downstream Segment--this segment includes activities such as refining, marketing, transporting petroleum products and petrochemical operations.

Energy Mining--capital expenditures associated with uranium and coal mining (excludes oil sands mining).

Equity--the book value of shareholders' paid-up capital, contributed surplus and retained earnings.

Exploration--includes all lease fees and land acquisition costs, geological and geophysical expenditures, and exploratory drilling. Exploratory drilling is generally defined as a well drilled outside a proven area, or within a proven area but to a previously untested horizon, in order to determine whether oil or gas reserves exist rather than to develop proved oil and gas reserves discovered by previous drilling. Also included are costs of dry wells, casing and other materials and equipment abandoned in place, and wells still in progress at year end.

External Financing--funds obtained from other than internal cash flow. Long-term debt and equity issues are examples of such funds.

Foreign Control--the Statistics Canada definition of control, which is used in monitoring reports, is based on whether Canadian or foreign shareholders have potential control over the company's overall operations. While control is generally based on ownership of 50% or more of voting shares, it is possible for effective control to be exercised with a smaller block of shares. Thus, regardless of the percentage ownership of voting rights by non-residents, if the company is effectively controlled by non-residents, then, for statistical purposes, 100% of its assets or revenues are assigned to the foreign controlled sector.

Foreign Ownership--estimates of foreign ownership are calculated using voting rights of shareholders, and apportioning revenues and assets on that basis. Non-voting rights are not included in the calculations.

Full Cost Accounting--under the full cost accounting method, all costs incurred in prospecting for reserves and in acquiring, exploring and developing properties within relatively large cost centers (such as countries) are capitalized and charged to expense (amortized) as the reserves deemed to be related to those costs are produced. Costs incurred include prospecting, leasing, acquisition, retention, exploration and development costs, together with associated indirect costs (i.e. that portion of general and administrative costs that can logically be related to prospecting, exploration, acquisition and development). Operating costs, such as lifting costs and general and administrative overhead applicable to current production and general corporate matters, are charged to expense as incurred.

Integrated Companies--these companies are generally selected on the basis that they had more than 1% of total industry revenues in both the upstream and downstream sectors. In addition, each of these companies has sizable refined product, marketing and distribution operations.

Internal Cash Flow--includes net income after tax plus exploration and development expenditures expensed in the current period, depreciation, depletion, amortization and deferred income taxes.

Junior Companies--this group consists of those reporting companies that are predominately exploration and production oriented and are not in either the integrated or senior company groupings. The junior companies usually generate less than 1% of total industry revenues in their upstream and downstream operations.

Long-term Debt--debt instruments that have a maturity date greater than one year after the close of the reporting period. In some cases, preferred shares may be treated as long-term debt when they are redeemable for a fixed amount without conversion privileges or voting rights.

Natural Gas and Gas Liquids Tax (NGGLT)--is a federal tax imposed on marketable pipeline gas and natural gas liquids. Marketable pipeline gas is defined as gas other than natural gas liquids or gas reinjected into a natural reservoir in Canada for purposes other than storage, or gas used in a gas processing plant or in a gas reprocessing plant. Natural gas liquids means ethanes, propanes, butanes or any mixtures thereof produced from gas at a gas processing plant or from marketable pipeline gas at a gas reprocessing plant.

Non-cash Charges--items expensed in the reporting period that do not require an actual financial outlay in that period, such as depreciation, depletion and amortization.

Non-conventional Heavy Oil--deposits below 23° API that are recoverable through enhanced recovery methods. Canadian deposits of heavy oil are typically in the 10 to 17° API range.

Oil Export Charge--is equal to the difference between the domestic price and the export price of heavy crude oil. Because of the low capacity of refineries in western Canada to process heavy crude oil, volumes of heavy crude which are surplus to Canada's requirements are exported. The federal government shares the export charge revenue with Alberta and Saskatchewan depending on the respective level of exports from each province.

Oil Sands--crude bitumen reserves from deposits that are generally solid unless heated and typically fall in the 6° to 10° API range. Athabasca, Peace River, Wabasca and Buffalo Head Hills are the main Canadian reserve areas.

Other Sources of Funds--sources such as the sale of assets or long-term investments, pre-payment received for future production, etc.

Other Uses of Funds--includes items such as acquisitions, purchases of used machinery and equipment, and long-term investments.

Petroleum Compensation Charge (PCC)--the federal government has indicated its intention to incorporate, over time, the total cost of oil imports and higher priced domestic oil into the consumer price for oil by means of a system of refinery levies. This is known as the Petroleum Compensation Charge (PCC). Revenues from the PCC are used to pay refiners an amount sufficient to reduce the average cost of imported oil to the average cost of domestic oil to Canadian refiners and to pay domestic producers of non-conventional crude oil the higher prices proposed by federal and provincial agreements.

Petroleum Incentives Program (PIP)--under this program (first announced in the NEP) direct incentives are to be paid in the form of PIP grants to qualifying enterprises carrying out specified oil and gas exploration, development, and production activities in Canada. The level of these incentives varies according to the area in which exploration and development occurs and is higher for those enterprises which are Canadian controlled and have specified levels of Canadian ownership. The Government of Alberta will administer and pay the incentives under the program for activities within Alberta and the federal government will administer the program elsewhere in Canada.

Petroleum and Gas Revenue Tax (PGRT)--this federal tax applies to gross oil and gas production revenue (less operating costs) and also to royalty income. Deductions for exploration and development expenditures, capital cost allowances, interest or Crown royalties, are not allowed in computing PGRT liabilities.

Senior Companies--this group is made up of several large companies, the principal activity of which is either upstream or downstream operations. Generally these companies have more than 1% of industry revenues of either upstream or downstream operations.

Successful Efforts Accounting--under the successful efforts accounting method, only those costs resulting directly in identifiable future benefits through the discovery, acquisition or development of specific reserves are capitalized. Costs that do not provide identifiable future benefits are generally charged to expense as incurred, or are written off as a loss when the costs are determined to be non-productive. The types of costs that are often charged to expense as incurred may include all or part of the costs relating to geological and geophysical studies, retention of undeveloped properties, non-productive exploration and development efforts, and general and administrative functions. Costs incurred to acquire undeveloped properties are often initially deferred and either held intact or amortized to expense. If the properties are found to be unproductive, they are written off.

Upstream--activities related to the search for, and development, production, extraction and recovery of crude oil, natural gas, natural gas liquids and sulphur, as well as the production of synthetic oil.

Working Capital--current assets (cash, short-term investments, accounts receivable, inventories) less current liabilities (accounts payable, debts and obligations maturing in less than one year).

Appendix II

COMPARISON OF PMA DATA WITH ESTIMATES OF 1981 INDUSTRY AGGREGATES

	PMA	Industry Aggregate Estimates	Column 1 as percentage of Column 2
	($ millions)		(%)
UPSTREAM CAPITAL EXPENDITURES			
Land and Lease	622	872(1)	71.3
Exploration (including land)	3765	4552(1)	82.7
Development and Production	2941	3167(1)	92.9
TOTAL EDP (in Canada)	6706	7719(1)	86.9
UPSTREAM PRODUCTION REVENUES	15547	17955(2)	86.6
REVENUES AND NET INCOME			
Gross sales (excluding sales tax and indirect tax)	41775	43159(3)	96.8
Net Income	3112	3247(3)	95.8
PRODUCTION STATISTICS			
CRUDE OIL AND LIQUIDS (thousands m^3/day)	220	257(2)	86.0
MARKETABLE NATURAL GAS (millions m^3/day)	161	187(2)	86.3

NOTES:

(1) SOURCE: Statistics Canada 26-213 1981 Net Cash Expenditures of the Petroleum Industry. The difference between the PMA and Statistics Canada estimates of investment is due to the fact that the Statistics Canada figures are collected from about 400 reporting companies compared to 10 for PMA.

(2) SOURCE: (Preliminary) Statistics Canada 26-006 Crude Petroleum and Natural Gas Production.

(3) SOURCE: Statistics Canada 61-003 Industrial Corporations - Financial Statistics.

Appendix III

STATISTICAL SCHEDULES

SCHEDULE A
INCOME AND EXPENSE STATEMENT

	UPSTREAM 1980 ($ MILLIONS)	UPSTREAM 1981 ($ MILLIONS)	UPSTREAM CHANGE (%)	DOWNSTREAM 1980 ($ MILLIONS)	DOWNSTREAM 1981 ($ MILLIONS)	DOWNSTREAM CHANGE (%)	OTHER OPERATIONS 1980 ($ MILLIONS)	OTHER OPERATIONS 1981 ($ MILLIONS)	OTHER OPERATIONS CHANGE (%)	FOREIGN ACTIVITIES 1980 ($ MILLIONS)	FOREIGN ACTIVITIES 1981 ($ MILLIONS)	FOREIGN ACTIVITIES CHANGE (%)	TOTAL OPERATIONS 1980 ($ MILLIONS)	TOTAL OPERATIONS 1981 ($ MILLIONS)	TOTAL OPERATIONS CHANGE (%)
TOTAL INDUSTRY															
TOTAL REVENUES	16076	16535	2.9	23568	29669	25.9	1383	3132	126.4	1325	1911	44.2	42353	51248	21.0
PGRT, NGGLT & PCC	0	956	-	862	4124	378.2	0	0	-	0	0	-	862	5080	-
ROYALTIES	4935	4895	-0.8	1813	2629	45.0	4	2	-44.4	79	92	15.8	6831	7618	11.5
TOT. REV. AFTER RYLTIES	11142	10684	-4.1	20893	22916	9.7	1379	3130	126.9	1246	1820	46.0	34660	38549	11.2
OPERATING COST	3400	4134	21.6	17849	20006	12.1	1122	3060	172.7	661	1081	63.5	23031	28290	22.8
E&D CHARGED TO OPER.	1404	1466	4.4	0	1	-	60	106	75.7	50	104	108.0	1514	1676	10.7
DEPRECIATION	372	484	-	381	419	9.9	65	137	110.2	52	139	169.7	870	1179	35.5
DEPLETION	381	309	-12.4	0	0	-43.7	5	5	1.1	114	127	11.5	700	641	-8.4
WRITE-OFFS. AMORT.	307	281	-8.6	19	21	11.2	-52	-110	-111.4	3	56	-	277	248	-10.6
NON-CASH CHARGES & EDP	2664	2739	2.8	400	441	10.2	78	138	76.1	219	426	94.8	3361	3744	11.4
INCOME BEFORE TAXES	5078	3811	-24.9	2644	2469	-6.6	179	-68	-138.0	367	313	-14.7	8267	6525	-21.1
CURRENT INCOME TAX	1038	1408	35.6	1031	845	-18.0	-27	-113	-321.5	32	46	41.4	2075	2186	5.4
INC. AFT. CURR. INC. TAX	4040	2403	-40.5	1613	1624	0.7	206	45	-77.9	334	267	-20.1	6192	4339	-29.9
DEFERRED INCOME TAX	1151	782	-32.1	199	256	61.3	43	35	-19.3	199	154	-2.9	1512	1227	-18.8
NET INCOME AFTER TAXES	2889	1621	-43.9	1454	1368	-5.9	163	11	-93.5	176	113	-35.6	4681	3112	-33.5
CASH FLOW	6704	5142	-23.3	2013	2065	2.6	284	183	-35.4	553	693	25.3	9553	8083	-15.4
TOTAL INTEGRATED															
TOTAL REVENUES	7183	6774	-5.7	18324	23383	27.6	208	398	91.8	16	21	30.5	25730	30577	18.8
PGRT, NGGLT & PCC	0	397	-	750	3672	389.8	0	0	-	0	0	-	750	4068	-
ROYALTIES	2341	2153	-8.0	1626	2296	41.2	0	0	-	0	0	-	3967	4449	12.2
TOT REV. AFTER RYLTIES	4842	4225	-12.7	15948	17416	9.2	208	398	91.8	16	21	30.5	21014	22060	5.0
OPERATING COST	1339	1394	4.1	13664	15181	11.1	193	330	70.6	5	5	-0.5	15202	16910	11.2
E&D CHARGED TO OPER.	825	903	9.4	0	0	-	35	76	114.5	0	0	-	860	978	13.7
DEPRECIATION	140	189	35.1	281	301	6.9	10	45	369.5	0	2	-	431	536	24.5
DEPLETION	90	66	-26.3	0	0	-	0	1	-	0	0	-	90	67	-25.6
WRITE-OFFS. AMORT.	139	162	16.8	20	15	-28.8	-22	-1	93.6	-4	1	133.0	133	176	32.4
NON-CASH CHARGES & EDP	1194	1320	10.6	302	315	4.5	23	120	-	-4	3	187.8	1514	1758	16.1
INCOME BEFORE TAXES	2309	1510	-34.6	1982	1920	-3.1	-8	-51	-	15	13	-16.0	4298	3392	-21.1
CURRENT INCOME TAX	634	809	27.6	855	671	-21.4	-21	-100	-371.2	4	4	-1.4	1471	1384	-5.9
INC. AFT. CURR. INC. TAX	1675	702	-58.1	1129	1248	10.7	13	49	280.9	11	8	-21.9	2826	2007	-29.0
DEFERRED INCOME TAX	377	167	-55.6	49	188	283.0	9	39	321.6	0	0	-	435	395	-9.4
NET INCOME AFTER TAXES	1298	534	-58.8	1079	1061	-1.7	3	9	170.7	11	8	-21.9	2391	1613	-32.6
CASH FLOW	2869	2022	-29.5	1429	1564	9.4	35	168	373.7	7	12	75.2	4341	3765	-13.3

Appendix III

STATISTICAL SCHEDULES

SCHEDULE A
INCOME AND EXPENSE STATEMENT

	UPSTREAM 1980 ($ MILLIONS)	UPSTREAM 1981 ($ MILLIONS)	UPSTREAM CHANGE (%)	DOWNSTREAM 1980 ($ MILLIONS)	DOWNSTREAM 1981 ($ MILLIONS)	DOWNSTREAM CHANGE (%)	OTHER OPERATIONS 1980 ($ MILLIONS)	OTHER OPERATIONS 1981 ($ MILLIONS)	OTHER OPERATIONS CHANGE (%)	FOREIGN ACTIVITIES 1980 ($ MILLIONS)	FOREIGN ACTIVITIES 1981 ($ MILLIONS)	FOREIGN ACTIVITIES CHANGE (%)	TOTAL OPERATIONS 1980 ($ MILLIONS)	TOTAL OPERATIONS 1981 ($ MILLIONS)	TOTAL OPERATIONS CHANGE (%)
FOREIGN CONTROLLED SENIOR															
TOTAL REVENUES	3028	3102	2.4	787	492	-37.5	13	7	-44.4	82	54	-34.4	3910	3655	-6.5
PGRT, NGGLT & PCC	0	183	-	0	21	-	0	0	-	0	0	-	0	204	-
ROYALTIES	950	930	-2.1	0	28	-	0	0	-	14	0	-	964	958	-0.6
TOT. REV. AFTER RYLTIES	2078	1988	-4.3	787	444	-43.6	13	7	-44.4	68	54	-21.3	2946	2493	-15.4
OPERATING COST	552	692	25.4	771	431	-44.1	12	-1	-108.3	14	20	38.1	1349	1141	-15.4
E&D CHARGED TO OPER.	382	352	-8.0	0	0	-	4	9	140.7	12	20	65.7	398	381	-4.4
DEPRECIATION	71	87	23.9	2	1	-26.0	0	0	137.5	7	8	18.7	79	97	22.3
DEPLETION	46	37	-19.3	0	0	-	0	0	-	3	1	-46.9	49	39	-20.8
WRITE-OFFS, AMORT.	122	86	-29.9	0	-0	-	-8	1	110.1	4	7	69.8	118	93	-21.2
NON-CASH CHARGES & EDP	622	562	-9.5	2	1	-39.9	-4	10	326.6	25	36	41.9	644	610	-5.4
INCOME BEFORE TAXES	903	734	-18.9	14	12	-15.3	5	-2	-141.4	29	-2	-106.0	953	743	-22.1
CURRENT INCOME TAX	236	356	50.6	1	5	-	-2	-1	74.6	7	8	20.9	241	368	52.4
INC. AFT. CURR. INC. TAX	668	378	-43.4	14	8	-45.4	7	-1	-120.9	22	-10	-144.4	711	374	-47.4
DEFERRED INCOME TAX	182	87	-52.2	3	-0	-116.7	0	1	-	9	-3	-138.3	194	84	-56.5
NET INCOME AFTER TAXES	486	291	-40.1	11	8	-28.7	7	-2	-133.0	13	-6	-148.3	517	290	-43.9
CASH FLOW	1290	941	-27.1	16	9	-44.7	3	9	241.3	47	26	-45.2	1356	984	-27.4
CANADIAN CONTROLLED SENIOR															
TOTAL REVENUES	4229	4678	10.6	4392	5740	30.7	399	1887	372.7	511	697	36.4	9532	13003	36.4
PGRT, NGGLT & PCC	0	269	-	113	432	282.6	0	0	-	0	0	-	113	697	-
ROYALTIES	1158	1237	6.8	186	305	63.8	1	1	3.6	15	14	-9.9	1361	1557	14.4
TOT. REV. AFTER RYLTIES	3071	3176	3.4	4093	5003	22.2	398	1886	373.8	496	684	37.9	8058	10749	33.4
OPERATING COST	1029	1348	30.9	3368	4354	29.3	393	2036	-	286	480	67.7	5037	8217	63.2
E&D CHARGED TO OPER.	98	127	29.8	0	1	-	11	9	-19.6	34	77	127.0	142	214	50.2
DEPRECIATION	116	123	6.1	95	112	18.6	19	46	141.4	20	32	55.7	250	313	25.1
DEPLETION	327	273	-16.6	0	0	-	2	4	143.2	38	68	77.8	367	345	-6.1
WRITE-OFFS, AMORT.	21	16	-24.3	-2	4	337.4	-41	-104	-161.3	-6	5	185.4	-28	-80	-189.7
NON-CASH CHARGES & EDP	562	539	-4.1	93	118	26.8	-9	-47	-	86	182	110.6	732	791	8.1
INCOME BEFORE TAXES	1480	1290	-12.8	632	531	-16.0	54	-103	-290.7	123	22	-82.2	2290	1740	-24.0
CURRENT INCOME TAX	143	208	45.3	170	167	-1.7	-6	-16	-174.1	10	-6	-154.3	318	354	11.3
INC. AFT. CURR. INC. TAX	1337	1081	-19.1	462	364	-21.3	60	-87	-245.4	113	28	-75.5	1972	1386	-29.7
DEFERRED INCOME TAX	472	433	-8.2	105	68	-34.7	-16	-34	-108.6	52	13	-75.9	612	480	-21.6
NET INCOME AFTER TAXES	865	648	-25.0	358	296	-17.3	76	-53	-169.7	61	15	-75.2	1360	906	-33.4
CASH FLOW	1898	1620	-14.7	555	482	-13.2	51	-134	-365.4	199	210	5.1	2704	2177	-19.5

Appendix III

STATISTICAL SCHEDULES

SCHEDULE A
INCOME AND EXPENSE STATEMENT

	UPSTREAM			DOWNSTREAM			OTHER OPERATIONS			FOREIGN ACTIVITIES			TOTAL OPERATIONS		
	1980 ($ MILLIONS)	1981 ($ MILLIONS)	CHANGE (%)	1980 ($ MILLIONS)	1981 ($ MILLIONS)	CHANGE (%)	1980 ($ MILLIONS)	1981 ($ MILLIONS)	CHANGE (%)	1980 ($ MILLIONS)	1981 ($ MILLIONS)	CHANGE (%)	1980 ($ MILLIONS)	1981 ($ MILLIONS)	CHANGE (%)
FOREIGN CONTROLLED JUNIOR															
TOTAL REVENUES	687	773	12.5	38	29	-22.8	141	132	-6.9	100	122	22.9	966	1056	9.2
PORT. NGGLT & PCC	0	41	-	0	0	-	0	0	-	0	0	-	0	41	-
ROYALTIES	205	237	15.4	0	0	-	0	0	-	7	1	-87.6	212	238	12.0
TOT.REV. AFTER RYLTIES	482	496	2.8	38	29	-22.8	141	132	-6.9	93	122	31.3	754	778	3.2
OPERATING COST	212	267	25.9	34	25	-26.0	106	107	0.7	30	45	51.9	382	444	16.3
E&D CHARGED TO OPER.	60	51	-14.5	0	0	-	0	0	-	2	3	39.6	62	55	-12.4
DEPRECIATION	17	24	39.4	1	1	-10.3	7	8	15.1	1	2	45.2	25	34	31.8
DEPLETION	34	36	5.4	0	0	-43.7	3	0	-	12	14	23.7	49	51	3.2
WRITE-OFFS, AMORT.	17	20	17.8	-0	0	-	0	4	-	6	11	79.9	22	34	50.8
NON-CASH CHARGES & EDP	128	131	2.2	1	1	-15.2	10	11	19.1	21	30	42.3	160	173	8.4
INCOME BEFORE TAXES	142	98	-31.0	3	3	9.6	25	13	-48.2	42	47	11.2	212	161	-24.2
CURRENT INCOME TAX	20	29	45.8	0	1	86.8	2	-3	-269.4	1	7	-	23	35	48.6
INC. AFT. CURR. INC. TAX	122	69	-43.7	3	3	-4.3	24	16	-33.9	41	39	-3.2	189	126	-33.2
DEFERRED INCOME TAX	37	26	-30.8	1	0	-97.4	9	7	-17.0	21	6	-71.6	67	39	-42.5
NET INCOME AFTER TAXES	85	43	-49.3	2	2	52.8	15	9	-43.4	20	33	67.6	122	88	-28.0
CASH FLOW	250	199	-20.2	4	3	-7.5	33	27	-18.8	62	69	12.3	348	299	-14.2
CANADIAN CONTROLLED JUNIOR															
TOTAL REVENUES	949	1208	27.3	27	24	-9.1	622	708	13.7	616	1016	64.9	2214	2956	33.5
PORT. NGGLT & PCC	0	70	-	0	0	-	0	0	-	0	0	-	0	70	-
ROYALTIES	281	339	20.7	0	0	-	3	1	-63.5	43	77	77.7	327	417	27.5
TOT.REV. AFTER RYLTIES	668	799	19.6	27	24	-9.1	619	707	14.1	573	939	63.9	1887	2469	30.8
OPERATING COST	267	433	62.2	12	16	30.1	457	588	28.7	326	531	63.1	1061	1567	47.7
E&D CHARGED TO OPER.	39	33	-15.1	0	0	-	11	12	15.6	1	3	117.5	51	48	-4.9
DEPRECIATION	29	60	110.9	3	4	58.9	30	38	28.6	24	96	308.4	85	199	135.0
DEPLETION	83	96	16.0	0	0	-	0	0	-12.1	62	44	-29.5	145	140	-3.4
WRITE-OFFS, AMORT.	9	-2	-124.6	0	2	-	19	-7	-136.5	3	22	-	31	25	-20.1
NON-CASH CHARGES & EDP	159	187	17.7	3	6	123.6	60	44	-26.3	90	175	94.4	311	412	32.3
INCOME BEFORE TAXES	243	179	-26.1	12	2	-80.5	103	75	-27.1	157	233	48.3	515	490	-4.8
CURRENT INCOME TAX	5	6	30.9	6	1	-80.3	1	5	-	10	32	229.7	21	45	115.4
INC. AFT. CURR. INC. TAX	238	173	-27.3	6	1	-80.6	102	70	-32.0	148	202	36.4	494	445	-9.9
DEFERRED INCOME TAX	83	69	-17.4	2	0	-71.6	42	21	-48.3	77	139	80.3	203	229	12.9
NET INCOME AFTER TAXES	155	104	-32.6	5	1	-83.7	61	48	-20.8	71	63	-11.3	291	216	-25.8
CASH FLOW	397	360	-9.3	9	7	-17.5	162	114	-29.9	238	376	58.4	805	857	6.5

STATISTICAL SCHEDULES

SCHEDULE B
SOURCES AND USES OF FUNDS

	1980 ($ MILLIONS) TOTAL INDUSTRY	1981	CHANGE (%)	1980 ($ MILLIONS) INTEGRATED COMPANIES	1981	CHANGE (%)	1980 ($ MILLIONS) FOREIGN CONTROLLED SENIOR	1981	CHANGE (%)
CASH GENERATED BY OPERATION	9553	8083	-15.4	4341	3765	-13.3	1356	984	-27.4
NET INCREASE IN LONG-TERM DEBT	2743	9398	242.6	27	783	-	22	0	-
ISSUE OF SHARES	1559	1826	17.1	871	8	-99.1	16	29	83.4
GRANTS (PIP & OTHERS)	0	767	-	0	128	-	0	34	-
ALL OTHER SOURCES	819	1203	46.9	188	279	43.5	118	153	29.6
WORKING CAPITAL DECREASE	677	1126	66.2	56	260	366.7	53	9	-83.7
TOTAL SOURCES OF FUNDS	15352	22402	45.9	5482	5214	-4.9	1564	1208	-22.8
TOTAL CAPITAL EXPEND IN CANADA	8448	9844	16.5	2944	3696	25.5	1211	825	-31.9
CAPITAL EXPEND IN U.S.A.	807	989	22.6	2	25	-	22	13	-41.5
OTHER FOREIGN CAPITAL EXPEND.	344	739	114.8	0	2	-	15	19	22.3
TOTAL FOREIGN CAPITAL EXPEND.	1151	1728	50.1	2	27	-	37	31	-15.3
TOTAL COMPANY CAPITAL EXPEND.	9598	11571	20.6	2946	3722	26.4	1248	856	-31.4
DIVIDENDS	940	1119	19.0	537	658	22.3	37	32	-15.5
REDUCTION OF EQUITY	160	239	48.8	66	113	70.1	26	83	220.2
TOTAL DIVID. & EQUITY REDUCT.	1101	1358	23.4	604	771	27.6	63	115	80.9
NET DECREASE IN LONG-TERM DEBT	610	661	8.2	176	43	-75.5	1	10	-
ALL OTHER APPLICATIONS	1626	6624	307.2	67	71	50.3	141	63	-55.3
WORKING CAPITAL INCREASE	2416	2189	-9.4	1710	607	-64.5	110	165	49.0
TOTAL APPLICATIONS OF FUNDS	15352	22402	45.9	5482	5214	-4.9	1564	1208	-22.8

	CANADIAN CONTROLLED SENIOR			FOREIGN CONTROLLED JUNIOR			CANADIAN CONTROLLED JUNIOR		
CASH GENERATED BY OPERATION	2704	2177	-19.5	348	299	-14.2	805	857	6.5
NET INCREASE IN LONG-TERM DEBT	1610	6094	278.6	308	429	39.3	777	2091	169.2
ISSUE OF SHARES	261	1370	-	88	42	-52.6	323	378	17.0
GRANTS (PIP & OTHERS)	0	490	-	0	9	-	0	106	-
ALL OTHER SOURCES	232	197	-15.0	93	93	-0.4	188	491	160.6
WORKING CAPITAL DECREASE	119	566	376.8	227	70	-69.3	224	222	-0.5
TOTAL SOURCES OF FUNDS	4925	10894	121.2	1064	942	-11.5	2316	4145	79.0
TOTAL CAPITAL EXPEND IN CANADA	2657	3538	33.2	543	485	-10.8	1093	1301	19.0
CAPITAL EXPEND IN U.S.A.	364	405	11.2	156	37	-76.3	263	509	93.4
OTHER FOREIGN CAPITAL EXPEND.	83	340	307.9	47	55	15.2	198	324	63.4
TOTAL FOREIGN CAPITAL EXPEND.	447	745	66.6	203	92	-55.0	461	833	80.5
TOTAL COMPANY CAPITAL EXPEND.	3104	4283	38.0	746	576	-22.8	1554	2134	37.3
DIVIDENDS	256	318	24.3	44	33	-24.3	65	78	20.3
REDUCTION OF EQUITY	10	9	-11.2	56	32	-42.7	3	2	-14.7
TOTAL DIVID & EQUITY REDUCT.	266	327	23.0	100	65	-34.6	68	80	18.9
NET DECREASE IN LONG-TERM DEBT	262	365	39.4	54	28	-48.7	118	215	82.9
ALL OTHER APPLICATIONS	938	4902	-	95	212	122.8	405	1375	239.6
WORKING CAPITAL INCREASE	355	1016	186.5	69	60	-12.5	172	341	98.3
TOTAL APPLICATIONS OF FUNDS	4925	10894	121.2	1064	942	-11.5	2316	4145	79.0

Appendix III

STATISTICAL SCHEDULES

SCHEDULE C

UPSTREAM CANADIAN CAPITAL EXPENDITURES BY LOCATION

	1980 ($ MILLIONS)	1981	CHANGE (%)	1980 ($ MILLIONS)	1981	CHANGE (%)	1980 ($ MILLIONS)	1981	CHANGE (%)
	TOTAL CANADIAN			PROVINCES			CANADA LANDS		
LAND & LEASE	997	622	-37.6	986	612	-38.0	11	11	-0.3
GEOLOG. &GEOPHYS.	602	598	-0.7	517	453	-12.4	85	145	71.0
EXPLORATION-DRILLING	2536	2545	0.4	1912	1497	-21.7	623	1048	68.2
TOTAL EXPLORATION	4135	3766	-8.9	3416	2562	-25.0	719	1204	67.5
DEVELOPMENT DRILLING	1036	1031	-0.5	1028	1028	-	8	3	-61.3
PRODUCTION	1095	1381	26.1	1047	1318	25.9	48	63	31.0
NON-CONVENT. HEAVY OIL	206	250	21.8	206	250	21.8	0	0	-
OIL SANDS	451	278	-38.4	451	278	-38.4	0	0	-
TOTAL UPSTREAM	6923	6706	-3.1	6148	5437	-11.6	775	1270	63.9

Appendix III

STATISTICAL SCHEDULES

SCHEDULE D
CAPITAL EXPENDITURES BY ACTIVITY

	1980 ($ MILLIONS) TOTAL INDUSTRY	1981	CHANGE (%)	1980 ($ MILLIONS) INTEGRATED COMPANIES	1981	CHANGE (%)	1980 ($ MILLIONS) FOREIGN CONTROLLED SENIOR	1981	CHANGE (%)
EXPLORATION	4135	3766	-8.9	1350	1220	-9.6	738	493	-33.2
DEVELOPMENT	1036	1031	-0.5	197	155	-21.6	189	87	-54.0
PRODUCTION	1095	1381	26.1	281	402	43.2	223	175	-21.7
NON-CONVENTIONAL HEAVY OIL	206	250	21.8	104	153	47.6	12	8	-33.9
OIL SANDS	451	278	-38.4	334	192	-42.4	29	31	7.5
TOTAL UPSTREAM	6923	6706	-3.1	2266	2122	-6.3	1191	793	-33.4
TOTAL DOWNSTREAM	755	1952	158.5	459	1126	145.5	3	1	-51.3
URANIUM	35	28	-19.3	18	11	-35.8	1	1	-42.0
COAL	91	320	-	76	293	285.4	2	11	-
ALL OTHERS	643	837	30.1	126	143	13.9	15	19	23.5
TOTAL CAPITAL EXPEND. IN CANADA	8448	9844	16.5	2944	3696	25.5	1211	825	-31.9
TOTAL CAPITAL EXPEND. ABROAD	1151	1728	50.1	2	27	-	37	31	-15.3
TOTAL COMPANY CAPITAL EXPEND.	9598	11571	20.6	2946	3722	26.4	1248	856	-31.4
	CANADIAN CONTROLLED SENIOR			FOREIGN CONTROLLED JUNIOR			CANADIAN CONTROLLED JUNIOR		
EXPLORATION	1318	1406	6.7	281	248	-11.7	447	398	-10.9
DEVELOPMENT	377	443	17.5	116	92	-20.5	156	254	62.4
PRODUCTION	361	559	54.9	81	74	-9.0	149	171	14.7
NON-CONVENTIONAL HEAVY OIL	87	62	-28.9	2	27	-	1	1	-27.4
OIL SANDS	66	44	-32.4	24	11	-54.5	0	0	-
TOTAL UPSTREAM	2209	2515	13.8	504	452	-10.3	754	824	9.4
TOTAL DOWNSTREAM	249	634	154.6	7	0	-	38	191	-
URANIUM	5	3	-53.4	7	8	11.7	4	5	56.0
COAL	13	15	17.4	0	1	-	1	0	-
ALL OTHERS	180	372	106.1	25	24	-4.8	297	279	-5.9
TOTAL CAPITAL EXPEND. IN CANADA	2657	3538	33.2	543	485	-10.8	1093	1301	19.0
TOTAL CAPITAL EXPEND. ABROAD	447	745	66.6	203	92	-55.0	461	833	80.5
TOTAL COMPANY CAPITAL EXPEND.	3104	4283	38.0	746	576	-22.8	1554	2134	37.3

Appendix III

STATISTICAL SCHEDULES

SCHEDULE E

BALANCE SHEET

	1980 ($ MILLIONS)	1981	CHANGE (%)	1980 ($ MILLIONS)	1981	CHANGE (%)	1980 ($ MILLIONS)	1981	CHANGE (%)
	TOTAL INDUSTRY			INTEGRATED COMPANIES			FOREIGN CONTROLLED SENIORS		
INVENTORIES	5256	7369	40.2	3452	4925	42.6	147	219	49.3
ACCOUNTS RECEIVABLE	6662	8184	22.8	3326	3608	8.5	905	1026	13.4
OTHER CURRENT ASSETS	4024	3950	-1.8	2681	1865	-30.4	219	290	32.5
TOTAL CURRENT ASSETS	15943	19503	22.3	9459	10398	9.9	1271	1536	20.9
NET FIXED ASSETS	32891	41765	27.0	9952	11737	17.9	3199	3377	5.5
OTHER LONG-TERM ASSETS	3857	8345	116.3	829	897	8.2	214	247	15.6
TOTAL ASSETS	52691	69612	32.1	20240	23032	13.8	4684	5160	10.2
ACCOUNTS PAYABLE	5721	7099	24.1	2771	3281	18.4	496	490	-1.2
OTHER CURRENT LIABIL.	3103	4215	35.9	1630	1712	5.0	155	270	74.4
TOTAL CURRENT LIABIL.	8823	11314	28.2	4401	4993	13.4	651	760	16.8
LONG TERM DEBT	9504	18509	94.7	1489	2223	49.3	156	147	-6.0
PREPAYMENT FOR DEF. PROD.	693	949	36.9	195	252	29.0	139	201	45.3
ACCUM. DEF. INCOME TAX	6580	7889	19.9	2539	2953	16.3	673	763	13.4
OTHER L.T. LIABILITIES	2610	2902	11.2	85	226	166.4	570	588	3.2
EQUITY	24480	28050	14.6	11531	12386	7.4	2495	2700	8.2
TOTAL LIA. DEF TAXES & EQUITY	52691	69613	32.1	20240	23032	13.8	4684	5160	10.2
WORKING CAPITAL	7119	8188	15.0	5058	5405	6.9	619	775	25.2
	CANADIAN CONTROLLED SENIORS			FOREIGN CONTROLLED JUNIORS			CANADIAN CONTROLLED JUNIORS		
INVENTORIES	1396	1880	34.7	51	59	16.8	211	286	35.8
ACCOUNTS RECEIVABLE	1662	2517	51.4	218	231	6.4	553	801	45.0
OTHER CURRENT ASSETS	709	1314	85.4	133	141	6.0	282	340	20.4
TOTAL CURRENT ASSETS	3766	5710	51.6	401	432	7.6	1046	1427	36.5
NET FIXED ASSETS	13553	17544	29.4	1970	2175	10.4	4215	6933	64.5
OTHER LONG-TERM ASSETS	1736	5761	231.8	295	502	69.9	783	937	19.7
TOTAL ASSETS	19056	29015	52.3	2667	3108	16.5	6044	9297	53.8
ACCOUNTS PAYABLE	1805	2487	37.8	214	218	1.9	435	623	43.1
OTHER CURRENT LIABIL.	815	1621	98.8	129	164	27.9	374	449	20.0
TOTAL CURRENT LIABIL.	2620	4107	56.8	342	382	11.6	809	1071	32.4
LONG TERM DEBT	4676	10576	126.2	930	1319	41.8	2252	4244	88.4
PREPAYMENT FOR DEF. PROD.	228	309	35.2	54	56	3.9	77	131	69.5
ACCUM. DEF. INCOME TAX	2561	3075	20.1	221	259	17.2	587	840	43.1
OTHER L.T. LIABILITIES	1788	1814	1.4	51	48	-5.9	117	226	93.7
EQUITY	7183	9134	27.2	1069	1044	-2.3	2201	2785	26.5
TOTAL LIA. DEF TAXES & EQUITY	19056	29015	52.3	2667	3108	16.5	6044	9297	53.8
WORKING CAPITAL	1146	1603	39.8	59	49	-16.6	237	356	50.5

Appendix III

STATISTICAL SCHEDULES

SCHEDULE F

GROSS PRODUCTION OF CRUDE OIL, NGL'S AND NATURAL GAS

	1980 (000 M3/DAY) TOTAL INDUSTRY	1981	CHANGE (%)	1980 (000 M3/DAY) INTEGRATED COMPANIES	1981	CHANGE (%)	1980 (000 M3/DAY) FOREIGN CONTROLLED SENIOR	1981	CHANGE (%)
CRUDE & NGL	244.6	214.8	-12.2	120.8	104.6	-13.4	48.1	40.4	-15.9
NAT. GAS-OIL EQUIVALENT	156.0	150.7	-3.4	45.4	42.6	-6.2	28.1	26.2	-6.7
TOTAL PRODUCTION	400.6	365.5	-8.8	166.2	147.1	-11.5	76.1	66.6	-12.5

	CANADIAN CONTROLLED SENIOR			FOREIGN CONTROLLED JUNIOR			CANADIAN CONTROLLED JUNIOR		
CRUDE & NGL	58.2	53.4	-8.2	8.3	7.8	-6.4	9.2	8.6	-6.7
NAT. GAS-OIL EQUIVALENT	52.2	48.5	-7.1	10.5	10.2	-2.6	19.9	23.3	17.1
TOTAL PRODUCTION	110.4	101.9	-7.7	18.8	18.0	-4.3	29.2	32.0	9.6

Appendix III

STATISTICAL SCHEDULES

Schedule C
SELECTED LARGE COMPANIES

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981
SOURCES					($ millions)						
INTERNAL SOURCES											
After-tax Income	561	683	1072	1337	1483	1457	1814	1973	3075	3864	2494
E & D Expenses	157	213	233	275	283	396	577	698	1007	1387	1486
Depreciation	284	310	346	369	402	463	477	521	611	678	785
Depletion	91	111	132	146	154	181	194	221	315	384	320
Write-offs and Amort.	51	55	71	89	86	114	159	144	110	178	225
Deferred Income Taxes	106	134	202	302	291	320	410	591	887	1021	791
TOTAL INTERNAL	1251	1505	2055	2518	2698	2931	3631	4148	6006	7512	6101
EXTERNAL SOURCES											
Long-term Debt Increase	196	275	258	465	486	776	585	763	1414	1753	4938
Equity Increase	73	41	99	21	22	107	221	308	456	1046	38
All Other	90	75	74	42	479	229	338	914	1084	787	1395
TOTAL EXTERNAL	359	391	431	528	987	1112	1144	1985	2954	3586	6371
TOTAL	1610	1895	2483	3044	3683	4042	4776	6133	8960	11098	12472
USES											
CAPITAL EXPENDITURES											
Upstream	724	749	850	1050	1201	1512	2169	2765	3769	5013	4285
Downstream	355	354	525	594	688	599	653	543	484	637	1437
TOTAL PETROLEUM	1079	1103	1375	1644	1889	2111	2822	3308	4253	5650	5722
Other in Canada	35	25	45	62	132	179	244	217	388	413	787
TOTAL IN CANADA	1114	1128	1420	1707	2020	2290	3066	3525	4641	6063	6509
Foreign	35	51	135	146	224	228	207	515	386	653	781
TOTAL CAPITAL EXPEND.	1148	1179	1555	1853	2244	2518	3273	4041	5127	6716	7290
Dividends	172	195	267	360	430	344	424	473	688	833	933
Equity Reduction	30	55	29	63	61	244	98	204	191	124	201
Long-Term Debt Reduction	167	212	593	388	232	351	289	174	179	321	246
Working Capital Increase	47	158	219	247	449	244	372	508	1392	2042	948
All Other Uses	45	97	154	133	267	342	320	734	1383	1062	2854
TOTAL USES	1610	1895	2483	3044	3683	4042	4776	6133	8960	11098	12472

Note: This component includes decreases in working capital.

Schedule H
INTERNATIONAL FLOWS OF FUNDS FOR REPORTING COMPANIES (1981)

	CURRENT ACCOUNT					CAPITAL ACCOUNT		
		Dividends		Business Service Payments				
	Interest	Direct[1]	Other	Direct[1]	Other	Direct[1]	Other	TOTAL
	($ millions)							
INTERNATIONAL TRANSACTIONS RELATED TO LONG-TERM INVESTMENTS IN CANADA								
Canadian Controlled	(65)	-	(29)	-	(5)	(15)	956	842
Foreign Controlled	(123)	(412)	(87)	(133)	(86)	(5617)	840	(5618)
INFLOWS (Outflows)	(188)	(412)	(116)	(133)	(91)	(5632)	1796	(4776)
INTERNATIONAL TRANSACTIONS RELATED TO LONG-TERM INVESTMENTS ABROAD								
Canadian Controlled	3	-	-	1	-	(399)	-	(395)
Foreign Controlled	104	-	-	22	-	(61)	-	65
INFLOWS (Outflows)	107	-	-	23	-	(460)	-	(330)
INTERNATIONAL TRANSACTIONS RELATED TO SHORT-TERM INVESTMENTS OTHER COUNTRIES								
Canadian Controlled	-	-	-	-	-	158	22	180
Foreign Controlled	-	-	-	-	-	58	51	109
INFLOWS (Outflows)						216	73	289
TOTAL (Long-term plus short-term)								
Canadian Controlled	(62)	-	(29)	1	(5)	(256)	978	627
Foreign Controlled	(19)	(412)	(87)	(111)	(86)	(5620)	891	(5444)
INFLOWS (Outflows)	(81)	(412)	(116)	(110)	(91)	(5876)	1869	(4817)

NOTE:

(1) Direct transactions are those which are between related companies (non-arms' length).

Appendix IV

DEFINITIONS OF AREAS OF TECHNOLOGY FOR R&D EXPENDITURES(1)

1. RENEWABLE RESOURCES

   (a) Solar energy includes passive, active and photovoltaics.

   (b) Biomass energy includes forest and agricultural biomass including plantations, harvesting and conversion.

   (c) Wind energy

   (d) Other renewable resources hydraulic energy (waves, tides, rivers), geothermal and peat.

2. TRANSPORTATION AND TRANSMISSION

   (a) Transportation of energy commodities includes pipelines, conveyor or vehicles, including ships and railways, and associated storage.

   (b) Transmission and distribution of electricity includes conversion of shaft energy to electricity, and storage of electricity.

3. CONSERVATION

   (a) Domestic and commercial buildings

   (b) Vehicles and other transportation systems includes more energy-efficient use of transportation systems; inter-modal shifts; and alternative fuel and drive systems.

   Industrial processes increasing energy efficiency of industrial processes including use of heat otherwise lost; and using energy derived indirectly by combusting industrial and municipal waste and by recycling energy-intensive materials.

   (d) Other conservation

4. FOSSIL FUELS

   (a) Crude oils and natural gas includes natural gas and crude oils from conventional and frontier reservoirs. Natural gas also includes gas derived from unconventional formations. Crude oils include all light crude oils and equivalent hydrocarbons not included in the definition of heavy crude oils.

      (i) Exploration and production excludes enhanced recovery; also excludes delivery to the refinery gate which is included as part of "Transportation of energy commodities" in this questionnaire.

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(1) These definitions are used by respondents for purposes of completing the Statistics Canada questionnaire Energy R&D Expenditures by Area of Technology.

(ii) Production by enhanced recovery includes incremental recovery of crude oils and/or natural gas by any secondary or tertiary means as distinct from primary recovery by natural depletion processes only.

(b) Oil sands and heavy crude oils--Oil sands include deposits of sand, shale and other rock aggregate containing bitumen which in its natural state is not recoverable at a commercial rate through a well. Heavy crude oils include those of high viscosities with API gravities less than 25° that are only recoverable to a limited extent from reservoirs by using natural depletion processes (primary recovery).

(i) Surface mined includes exploration, surface mining, production and upgrading to a refinery feedstock.

(ii) In-situ produced includes in-situ production and upgrading to a refinery feedstock; and enhanced recovery by any secondary or tertiary means as distinct from primary recovery by natural depletion processes only.

(c) Refining includes refining, processing and cleaning of crude oils and natural gases; excludes bitumen upgrading.

(d) Coal includes supply (exploration, mining and beneficiation including slurry preparation; combustion (including environmental control and coal slurries); and conversion (to solids, liquids and gases, including coprocessing of coal and bitumen). Excludes transportation to point of use, which is included as part of "Transportation of energy commodities" in this questionnaire.

5. NUCLEAR--INCLUDES BOTH FISSION AND FUSION ENERGY

(a) Fuel exploration, mining and preparation

(b) Energy generation includes generation of electricity and heat by nuclear reactors; and safety and wastes management.

6. OTHER (specify)--FOR EXAMPLE: HYDROGEN; HEAT PUMPS; HEAT AND MECHANICAL STORAGE

Appendix V

CHANGES TO THE PCC IN 1980 AND 1981

	Type of Change	Amount of Change ($/m^3)	Amount of Change ($/bbl)	Level of PCC including other special charges ($/m^3)	Level of PCC including other special charges ($/bbl)
1980					
April 1	increase	0.94	0.15	6.29	1.00
July 10	increase	4.72	0.75	11.01	1.75
November 1	increase	5.03	0.80	16.05	2.55
1981					
January 1	increase	15.73	2.50	31.78	5.05
March 1	Special Compensation Levy imposed	4.72	0.75	36.50	5.80
May 1	Canadian Ownership Charge imposed	7.24	1.15	43.74	6.95
June 1	Special Compensation Levy increase	6.92	1.10	50.66	8.05
June 3	increase	7.87	1.25	58.52	9.30
September 22	Special Compensation Levy abolished	(11.64)	(1.85)		
	PCC increase	11.64	1.85	58.52	9.30
November 30	PCC decrease	(11.64)	(1.85)	46.88	7.45